



1407 West North Temple, Suite 330  
Salt Lake City, Utah 84116

June 8, 2016

**VIA OVERNIGHT DELIVERY**

Ms. Jean D. Jewell  
Commission Secretary  
Idaho Public Utilities Commission  
472 W. Washington  
Boise, ID 83702

RECEIVED  
2016 JUN -8 AM 9:09  
IDAHO PUBLIC  
UTILITIES COMMISSION

PAC-E-12-02

**Re: PAC-E-04-07 2015 Service Quality & Customer Guarantee Report for the period  
January 1 through December 31, 2015.**

Dear Ms. Jewell:

Rocky Mountain Power, a division of PacifiCorp, hereby provides a copy of the 2015 Service Quality & Customer Guarantee report. This report is provided pursuant to a merger commitment made during the PacifiCorp and ScottishPower<sup>1</sup> merger. The Company committed to implement a five-year Service Standards and Customer Guarantees program. The purposes behind these programs were to improve service to customers and to emphasize to employees that customer service is a top priority. Towards the end of the five-year merger commitment the Company filed an application<sup>2</sup> with the Commission requesting authorization to extend these programs.

If there are any additional questions regarding this report please contact Ted Weston at (801) 220-2963.

Sincerely,

*Ted Weston /um*

Ted Weston  
Manager, Idaho Regulatory Affairs

Enclosures

cc: Rick Sterling  
Terri Carlock  
Beverly Barker

<sup>1</sup> Case No. PAC-E-99-01

<sup>2</sup> Case No. PAC-E-04-07



# **IDAHO SERVICE QUALITY REVIEW**

**January 1 – December 31, 2015  
Report**

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## **EXECUTIVE SUMMARY**

Rocky Mountain Power has a number of Customer Service Standards and Service Quality Measures with performance reporting mechanisms currently in place. These standards and measures are defined by Rocky Mountain Power's target performance (both personnel and network reliability performance) in delivering quality customer service. The Company developed these standards and measures using relevant industry standards for collecting and reporting performance data. In some cases, Rocky Mountain Power has expanded upon these standards. In other cases, largely where the industry has no established standards, Rocky Mountain Power has developed metrics, targets and reporting. While industry standards are not focused around threshold performance levels, the Company has developed targets or performance levels against which it evaluates its performance. These standards and measures can be used over time, both historically and prospectively, to measure the service quality delivered to our customers.

## **1 SERVICE STANDARDS PROGRAM SUMMARY<sup>1</sup>**

### **1.1 Idaho Customer Guarantees**

<u>Customer Guarantee 1:</u> Restoring Supply After an Outage	The Company will restore supply after an outage within 24 hours of notification with certain exceptions as described in Rule 25.
<u>Customer Guarantee 2:</u> Appointments	The Company will keep mutually agreed upon appointments, which will be scheduled within a two-hour time window.
<u>Customer Guarantee 3:</u> Switching on Power	The Company will switch on power within 24 hours of the customer or applicant's request, provided no construction is required, all government inspections are met and communicated to the Company and required payments are made. Disconnections for nonpayment, subterfuge or theft/diversion of service are excluded.
<u>Customer Guarantee 4:</u> Estimates For New Supply	The Company will provide an estimate for new supply to the applicant or customer within 15 working days after the initial meeting and all necessary information is provided to the Company.
<u>Customer Guarantee 5:</u> Respond To Billing Inquiries	The Company will respond to most billing inquiries at the time of the initial contact. For those that require further investigation, the Company will investigate and respond to the Customer within 10 working days.
<u>Customer Guarantee 6:</u> Resolving Meter Problems	The Company will investigate and respond to reported problems with a meter or conduct a meter test and report results to the customer within 10 working days.
<u>Customer Guarantee 7:</u> Notification of Planned Interruptions	The Company will provide the customer with at least two days' notice prior to turning off power for planned interruptions.

*Note: See Rules for a complete description of terms and conditions for the Customer Guarantee Program.*

<sup>1</sup> On June 29, 2012, in Docket PAC-E-12-02 and Order 32583, the Commission ordered that Rocky Mountain Power had delivered upon commitments it made in pursuant to the MidAmerican transaction in PAC-E-05-08 and Order 29998. The Commission also ordered the acceptance of modifications to the Service Standards Program proposed by Rocky Mountain Power, as shown on Page 4.

## 1.2 Idaho Performance Standards

<u>Network Performance Standard 1:</u> Report System Average Interruption Duration Index (SAIDI)	The Company will report Total, Underlying, and Controllable SAIDI and identify annual Underlying baseline performance targets for the reporting period. For actual performance variations from baseline, explanations of performance will be provided. The Company will also report rolling twelve month performance for Controllable, Non-Controllable and Underlying distribution events.
<u>Network Performance Standard 2:</u> Report System Average Interruption Frequency Index (SAIFI)	The Company will report Total, Underlying, and Controllable SAIFI and identify annual Underlying baseline performance targets for the reporting period. For actual performance variations from baseline, explanations of performance will be provided. The Company will also report rolling twelve month performance for Controllable, Non-Controllable and Underlying distribution events.
<u>Network Performance Standard 3:</u> Improve <sup>2</sup> Under-Performing Areas	Annually the Company will select at least one underperforming area based upon a reliability performance indicator <sup>3</sup> (RPI). Within five years after selection the Company will reduce the RPI by an average of 10% for the areas selected in a given year. The Company will identify the criteria used for determining these areas and the plans <sup>4</sup> to address them.
<u>Network Performance Standard 4:</u> Supply Restoration	The Company will restore power outages due to loss of supply or damage to the distribution system within three hours to 80% of customers on average.
<u>Customer Service Performance Standard 5:</u> Telephone Service Level	The Company will answer 80% of telephone calls within 30 seconds. The Company will monitor customer satisfaction with the Company's Customer Service Associates and quality of response received by customers through the Company's eQuality monitoring system.
<u>Customer Service Performance Standard 6:</u> Commission Complaint Response / Resolution	The Company will a) respond to at least 95% of non-disconnect Commission complaints within three working days and will b) respond to at least 95% of disconnect Commission complaints within four working hours, and will c) resolve 95% of informal Commission complaints within 30 days.

*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude those classified as Major Events.*

<sup>2</sup> When in the future, the Company discovers that marginal improvement costs outweigh marginal improvement benefits, the Company can propose modifications to the Performance Standards Program to recognize that maintaining performance levels is appropriate.

<sup>3</sup> Reliability performance indicators (RPI) will be calculated by aggregating customer transformer level SAIDI, SAIFI, and MAIFI, and are exclusive of major events as calculated by IEEE 1366-2012; they are a modification to the Company's historic CPI. RPI excludes breaker lockout events.

<sup>4</sup> Prospectively, the Company will work with Commission Staff to determine methods to report the target area performance and cost-benefit results.

## 2 RELIABILITY PERFORMANCE

During 2015, the Company experienced mixed reliability results, with underlying interruption duration (SAIDI) that was unfavorable to plan while interruption frequency (SAIFI) performance that was favorable to plan. Results for Idaho underlying performance can be seen in subsections 2.1 and 2.2 below.

Three outage events during the reporting period meet the Company's Idaho major event threshold level<sup>5</sup> for exclusion from underlying performance results.

Major Events 2015		
Date	Cause	SAIDI
July 29, 2015	Equipment Failure	17.25
August 1, 2015	Loss of Supply	30.80
August 29-30, 2015	Lightning	18.38

### Major Event General Descriptions

- 7/29/2015: A line fault occurred on the Rigby-Thornton transmission line. During the event three substations, 12 circuits, and 16,496 customers were without power. Personnel were promptly dispatched to the area. An inspection of the Rigby-Thornton tap showed the insulator had burned, causing the circuit breaker to trip.
- 8/1/2015: Idaho experienced two loss of supply events. The first event occurred in Shelley, when a faulty low oil sensor triggered a transformer at the Sugarmill Substation causing a lockout. The transformer is a source to the Sandcreek, Ammon, and Ucon Substations, and caused outages to a total of 10 circuits, impacting 16,222 customers for just over 2 hours. The second event occurred at in Montpelier, when the bus on the Grace 161 kV line locked out, de-energizing the 46kv transmission lines leaving the substation. These lines feed six surrounding distribution substations. The incident event impacted 10 distribution lines and 4,168 customers for less than 2 hours.
- 8/29/2015 – 8/30/2015: A severe thunderstorm brought lightning, wind, and heavy rain to southeast Idaho. During the storm two significant outages occurred. The first outage occurred in Mud Lake when high winds, specifically micro-bursts, caused damage to almost a dozen poles. The outage affected 431 customers, with restorations ranging from 2 hours to 17.5 hours. The second significant impact occurred at 10:58 pm, when lightning made contact with the Ucon substation, faulting the substation and de-energizing two circuits, affecting 2,664 customers for 6 hours and 53 minutes.

<sup>5</sup> Major event threshold shown below:

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
2015	869,108	15.95	1,237,173
2016	76,971	14.82	1,141,067

**Significant Events**

In 2015, 13 significant event days<sup>6</sup> were recorded in the period, which account for 83 SAIDI minutes; about 42% of the reporting period's underlying 197 SAIDI minutes. Significant event days add substantially to year on year cumulative performance results; fewer significant event days generally result in better reliability for the reporting period, while more significant event days generally mean poorer reliability results.

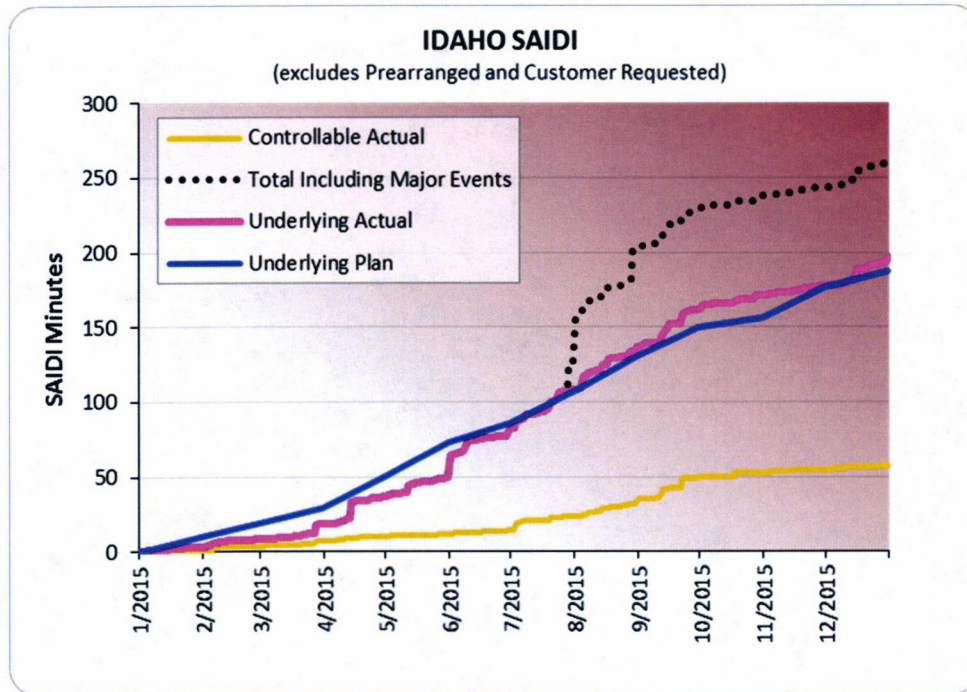
<b>Significant Event Days 2015</b>			
<b>Date</b>	<b>Cause: General Description</b>	<b>Event SAIDI</b>	<b>% of Total Year End SAIDI</b>
<b>March 28, 2015</b>	Snow and wind storm cause pole fire and downed line.	6.07	3.1%
<b>April 14, 2015</b>	Wind and snow storm related outage and loss of supply	10.98	5.6%
<b>May 12, 2015</b>	Loss of transmission: no cause found. Lightning reported in the area	5.14	2.6%
<b>June 1, 2015</b>	Wind Storm caused several downed lines and poles.	14.47	7.3%
<b>June 9, 2015</b>	Wind Storm, trees on lines.	5.09	2.6%
<b>July 3, 2015</b>	Neutral line down across primary lines	4.32	2.2%
<b>July 20, 2015</b>	Flash occurred at substation of manufacturing plant causing a loss of transmission.	5.20	2.6%
<b>July 24, 2015</b>	Tree limb fell on primary line	4.48	2.3%
<b>August 5, 2015</b>	Wind and Lightning storm, loss of supply and windblown downed equipment.	7.69	3.9%
<b>August 17, 2015</b>	Loss of transmission, Bird nest caused flashover. Fire restriction line patrol before restoration.	4.31	2.2%
<b>September 22, 2015</b>	Equipment failure. Power fuses blew on substation transformer	6.40	3.2%
<b>December 16, 2015</b>	Loss of transmission: line down	5.02	2.5%
<b>December 31, 2015</b>	Loss of transmission: line down	3.93	2.0%
<b>TOTAL</b>		<b>83.10</b>	<b>42.2%</b>

<sup>6</sup> On a trial basis, the Company established a variable of 1.75 times the standard deviation of its natural log SAIDI results.

## 2.1 System Average Interruption Duration Index (SAIDI)

The Company's underlying interruption duration performance during 2015 was unfavorable to plan.

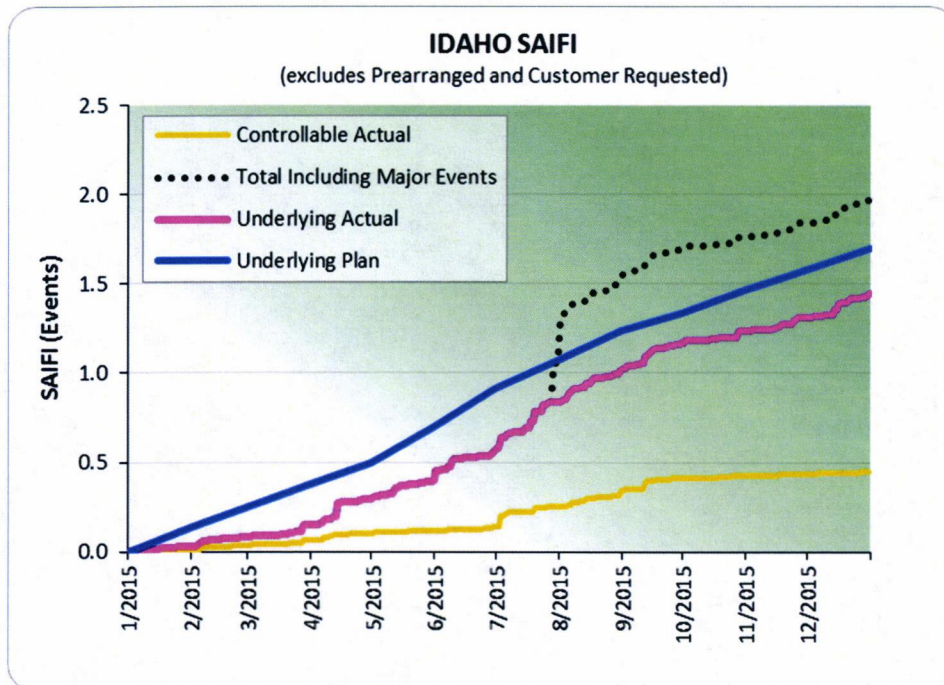
IDAHO	January 1 through December 31, 2015	
	SAIDI Actual	2015 SAIDI Plan
Total (major event included)	263	N/A
Underlying	197	187
Controllable	58	N/A



## 2.2 System Average Interruption Frequency Index (SAIFI)

The Company's underlying interruption frequency performance results for 2015 were favorable plan.

IDAHO	January 1 through December 31, 2015	
	SAIFI Actual	2015 SAIFI Plan
Total (major event included)	1.981	N/A
Underlying	1.452	1.70
Controllable	0.450	N/A



## 2.3 Momentary Average Interruption Event Frequency Index (MAIFI<sub>e</sub>)

The Company annually reports the occurrence of short interruptions using two different metrics<sup>7</sup>. The chart below displays, for the circuits with SCADA devices, the operating area weighted MAIFI<sub>e</sub> performance.

January 1 through December 31, 2015	
Operating Area	MAIFI <sub>e</sub> (SCADA)
Montpelier	Not applicable
Preston	0.857
Rexburg	0.776
Shelley	1.313

In the table below, all circuits that do not have SCADA are evaluated for performance, and where the breaker counters appear unusual, these counts are investigated and necessary corrections undertaken. Highlights of current findings for breakers with unusual levels of counter operations are summarized here.

- Lava #11: the breaker count was incorrectly recorded. The breaker counter leads with nines, as opposed to zeros, and was incorrectly recorded into the system as such. Records have been updated to reflect the correct trips as 3.
- Clifton #11: breaker readings between July 2015 and October 2015 indicate 59 of the total 65 operations taken in 2015. Extensive maintenance work was performed on the line during this period causing an increase breaker trips; maintenance trips increment the counter, but do not result in impacts to customers.
- Holbrook #11: 57 trips were added to the count as a result of the difference between the last recorded reading in 2014 (August 11, 2014) and the first reading in 2015 (February 2, 2015). Since then only 3 breaker operations occurred, from February to October 2015.
- Egin #11: the circuit breaker log shows a total of 26 trips in 2015. It appears a recording error has occurred and will be corrected.

January 1 through December 31, 2015 (includes Major Events)			
Operating Area	Circuit Name	Circuit ID	Operations
MONTPELIER	ALEXANDER #11	ALX11	2
MONTPELIER	ARIMO #11	ARM11	6
MONTPELIER	ARIMO #12	ARM12	19
MONTPELIER	BANCROFT #11	BAN11	10
MONTPELIER	BANCROFT #12	BAN12	1
MONTPELIER	CHESTERFIELD #11	CHS11	2
MONTPELIER	CHESTERFIELD #12 HATCH	CHS12	5
MONTPELIER	COVE #12	COV12	3
MONTPELIER	EIGHT MILE #11	EGT11	10
MONTPELIER	GEORGETOWN #11	GRG11	0
MONTPELIER	GRACE #11	GCE11	14
MONTPELIER	GRACE #12	GCE12	3
MONTPELIER	HENRY #11	HRV11	0
MONTPELIER	HORSLEY #11	HRS11	1

<sup>7</sup> Idaho state commitment I10.

On January 31, 2005, the Commission accepted Rocky Mountain Power's proposal to eliminate its Network Performance Standard relating to Momentary Average Interruption Frequency Index (MAIFI) in light of the Company's commitment to develop an acceptable alternative to MAIFI as soon as possible. The Company has developed its proposed measurement plan and is scheduled to present to the Commission Staff at its next reliability meeting (scheduled for December 20, 2005). Within 60 days after this meeting, the Company will file the plan with the Commission. MEHC and Rocky Mountain Power commit to implement this plan and provide the results of these calculations to Commission Staff and other interested parties in reliability review meetings.

## Service Quality Review

January – December 2015

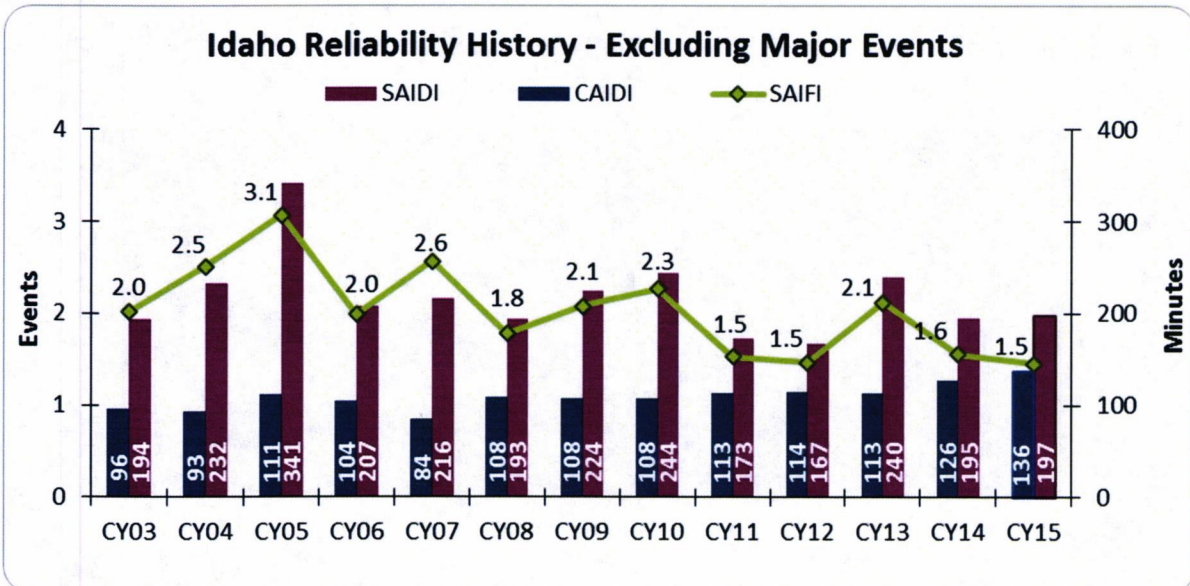
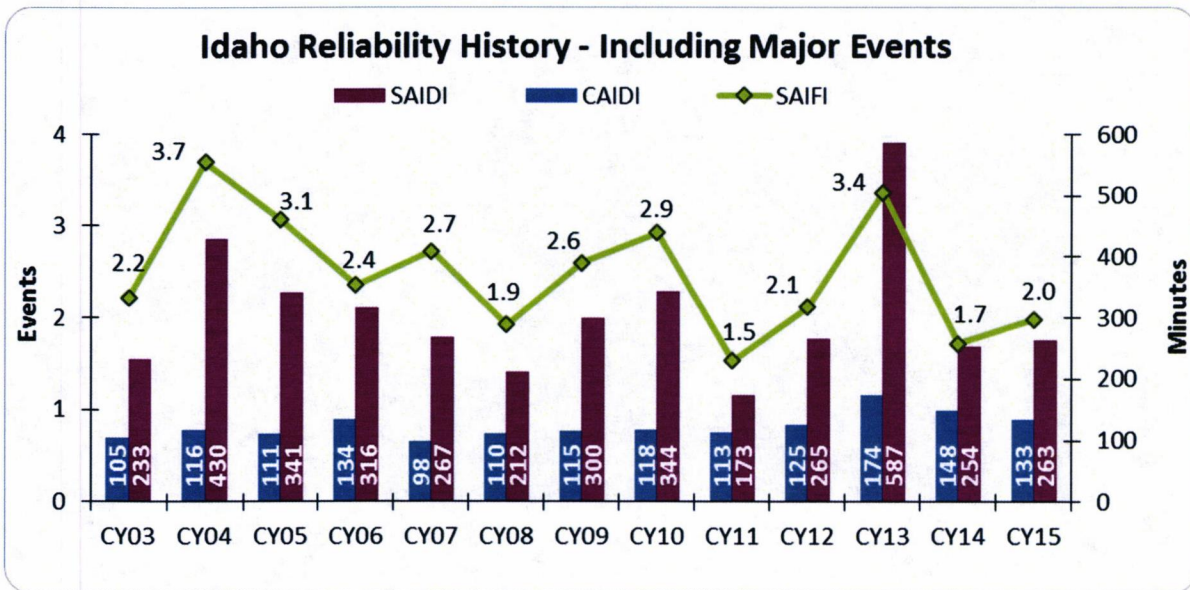
MONTPELIER	INDIAN CREEK #11	IND11	14
MONTPELIER	LAVA #11	LVA11	99911
MONTPELIER	LUND #11	LND11	28
MONTPELIER	MCCAMMON #11	MCC11	12
MONTPELIER	MCCAMMON #12	MCC12	0
MONTPELIER	MONTPELIER #11	MNT11	1
MONTPELIER	MONTPELIER #13	MNT13	1
MONTPELIER	MONTPELIER #14	MNT14	1
MONTPELIER	RAYMOND #11 NORTH TO GENEVA	RAY11	11
MONTPELIER	RAYMOND #12 SOUTH TO PEGRAM	RAY12	14
MONTPELIER	ST CHARLES #11	STC11	5
PRESTON	CLIFTON #11 DAYTON & BANIDA	CLF11	65
PRESTON	CLIFTON #12 CLIFTON/OXFORD/SWANLAKE	CLF12	3
PRESTON	DOWNEY #11	DWN11	4
PRESTON	DOWNEY #12	DWN12	0
PRESTON	HOLBROOK #11	HLB11	60
PRESTON	MALAD #11	MLD11	3
PRESTON	MALAD #12	MLD12	3
PRESTON	MALAD #13	MLD13	4
PRESTON	PRESTON #11	PRS11	19
PRESTON	PRESTON #12	PRS12	37
PRESTON	PRESTON #13	PRS13	31
PRESTON	TANNER #11 MINK CREEK	TNR11	12
PRESTON	TANNER #12 RIVERDALE/TREASURETON	TNR12	2
PRESTON	WESTON #12 NORTH TO DAYTON	WST12	7
PRESTON	WESTON#11 SOUTH - WESTON/FAIRVIEW	WST11	4
REXBURG	ANDERSON #11 WEST	AND11	0
REXBURG	ANDERSON #12 EAST AND NORTH	AND12	0
REXBURG	ANDERSON #13 NORTH	AND13	0
REXBURG	ARCO #11	ARC11	1
REXBURG	ARCO #12	ARC12	1
REXBURG	ARCO #13	ARC13	1
REXBURG	ASHTON #11	ASH11	1
REXBURG	BELSON #11	BLS11	0
REXBURG	BELSON #12	BLS12	0
REXBURG	BERENICE #21	BRN21	1
REXBURG	BERENICE #22	BRN22	21
REXBURG	CAMAS #11	CMS11	1
REXBURG	CAMAS #12	CMS12	0
REXBURG	CANYON CREEK # 22	CNY22	1
REXBURG	CANYON CREEK #21	CNY21	9
REXBURG	DUBOIS #11	DBS11	1
REXBURG	DUBOIS #12	DBS12	0
REXBURG	EASTMONT #11	EST11	4
REXBURG	EASTMONT #12	EST12	8
REXBURG	EGIN #11	EGN11	146
REXBURG	EGIN #12	EGN12	4
REXBURG	HAMER #11	HMR11	23
REXBURG	HAMER #12	HMR12	6
REXBURG	MENAN #11	MNN11	0
REXBURG	MENAN #12	MNN12	0
REXBURG	MENAN #13	MNN13	0
REXBURG	MILLER #11	MLL11	0
REXBURG	MILLER #12	MLL12	0
REXBURG	MOODY #11	MDY11	0
REXBURG	MOODY #12	MDY12	0
REXBURG	MOODY #13	MDY13	1
REXBURG	MUDLAKE #11	MDL11	0
REXBURG	MUDLAKE #12	MDL12	1
REXBURG	NEWDALE #11	NWD11	0
REXBURG	NEWDALE #12	NWD12	0

REXBURG	NEWDALE #13	NWD13	1
REXBURG	RENO #11	REN11	3
REXBURG	RENO #12	REN12	0
REXBURG	RENO #13	REN13	0
REXBURG	REXBURG #11	RXB11	0
REXBURG	REXBURG #12	RXB12	2
REXBURG	REXBURG #13	RXB13	0
REXBURG	REXBURG #14	RXB14	0
REXBURG	REXBURG #15	RXB15	0
REXBURG	REXBURG #16	RXB16	0
REXBURG	RIGBY #11	RGB11	4
REXBURG	RIGBY #12	RGB12	0
REXBURG	RIGBY #13	RGB13	0
REXBURG	RIGBY #14	RGB14	0
REXBURG	RIRIE #12	RIR12	0
REXBURG	ROBERTS #11	RBR11	1
REXBURG	ROBERTS #12	RBR12	0
REXBURG	RUBY #11	RBV11	5
REXBURG	SANDUNE #21	SDN21	3
REXBURG	SANDUNE #22	SDN22	0
REXBURG	SMITH #11	SMT11	18
REXBURG	SMITH #12	SMT12	9
REXBURG	SMITH #13	SMT13	3
REXBURG	SMITH #14	SMT14	1
REXBURG	SOUTH FORK #11 IDAHO PACIFIC POTATO	SFK11	0
REXBURG	SOUTH FORK #13 ANTELOPE FLATS	SFK13	0
REXBURG	ST ANTHONY #11	STA11	1
REXBURG	ST ANTHONY #12	STA12	0
REXBURG	ST ANTHONY #13	STA13	0
REXBURG	SUGAR CITY #11	SGR11	0
REXBURG	SUGAR CITY #12	SGR12	0
REXBURG	SUGAR CITY #13	SGR13	0
REXBURG	SUGAR CITY #14	SGR14	0
REXBURG	SUNNYDELL #11	SNN11	1
REXBURG	SUNNYDELL #12	SNN12	2
REXBURG	TARGHEE #11	TRG11	0
REXBURG	TARGHEE #12	TRG12	0
REXBURG	THORNTON #11	THR11	1
REXBURG	THORNTON #12	THR12	1
REXBURG	WATKINS #11 NORTH AND EAST	WTK11	5
REXBURG	WEBSTER #11 EAST AND SOUTH	WBS11	16
REXBURG	WEBSTER #12 NORTH	WBS12	4
REXBURG	WEBSTER #14	WBS14	35
REXBURG	WINSPIER #21	WNS21	0
REXBURG	WINSPIER #22	WNS22	0
SHELLEY	AMMON #11	AMM11	5
SHELLEY	AMMON #12	AMM12	1
SHELLEY	Cinder Butte #11	CIB11	0
SHELLEY	CINDER BUTTE #13	CIB13	1
SHELLEY	Cinder Butte #17	CIB17	4
SHELLEY	CLEMENTS #11	CLE11	11
SHELLEY	CLEMENTS #12	CLE12	18
SHELLEY	GOSHEN #11	GSH11	0
SHELLEY	GOSHEN #12	GSH12	8
SHELLEY	GOSHEN #13	GSH13	3
SHELLEY	HAYES #11	HYS11	0
SHELLEY	HAYES #12	HYS12	1
SHELLEY	HAYES #13	HYS13	11
SHELLEY	HOOPES #11 WEST	HPS11	8
SHELLEY	HOOPES #12 NORTH	HPS12	0
SHELLEY	IDAHO FALLS #11	IDF11	2

SHELLEY	IDAHO FALLS #12	IDF12	37
SHELLEY	IDAHO FALLS #13	IDF13	9
SHELLEY	IDAHO FALLS #14	IDF14	3
SHELLEY	JEFFCO #21	JFF21	22
SHELLEY	JEFFCO #22	JFF22	3
SHELLEY	KETTLE #21	KTT21	18
SHELLEY	KETTLE #22	KTT22	8
SHELLEY	MERRILL #11	MRR11	19
SHELLEY	MERRILL #12	MRR12	16
SHELLEY	MERRILL #13	MRR13	16
SHELLEY	MERRILL #14	MRR14	8
SHELLEY	OSGOOD #11	OSG11	26
SHELLEY	OSGOOD #12	OSG12	5
SHELLEY	OSGOOD #13	OSG13	6
SHELLEY	OSGOOD #14	OSG14	9
SHELLEY	SANDCREEK #11	SND11	1
SHELLEY	SANDCREEK #12	SND12	5
SHELLEY	SANDCREEK #13	SND13	1
SHELLEY	SANDCREEK #14	SND14	11
SHELLEY	SANDCREEK #15	SND15	32
SHELLEY	SANDCREEK #16	SND16	7
SHELLEY	SHELLEY #11	SHL11	27
SHELLEY	SHELLEY #12	SHL12	0
SHELLEY	SHELLEY #13	SHL13	0
SHELLEY	SHELLEY #14	SHL14	6
SHELLEY	UCON #11	UCN11	2
SHELLEY	UCON #12	UCN12	5
SHELLEY	WATKINS #12 SOUTH THEN EAST	WTK12	7

## 2.4 Reliability History

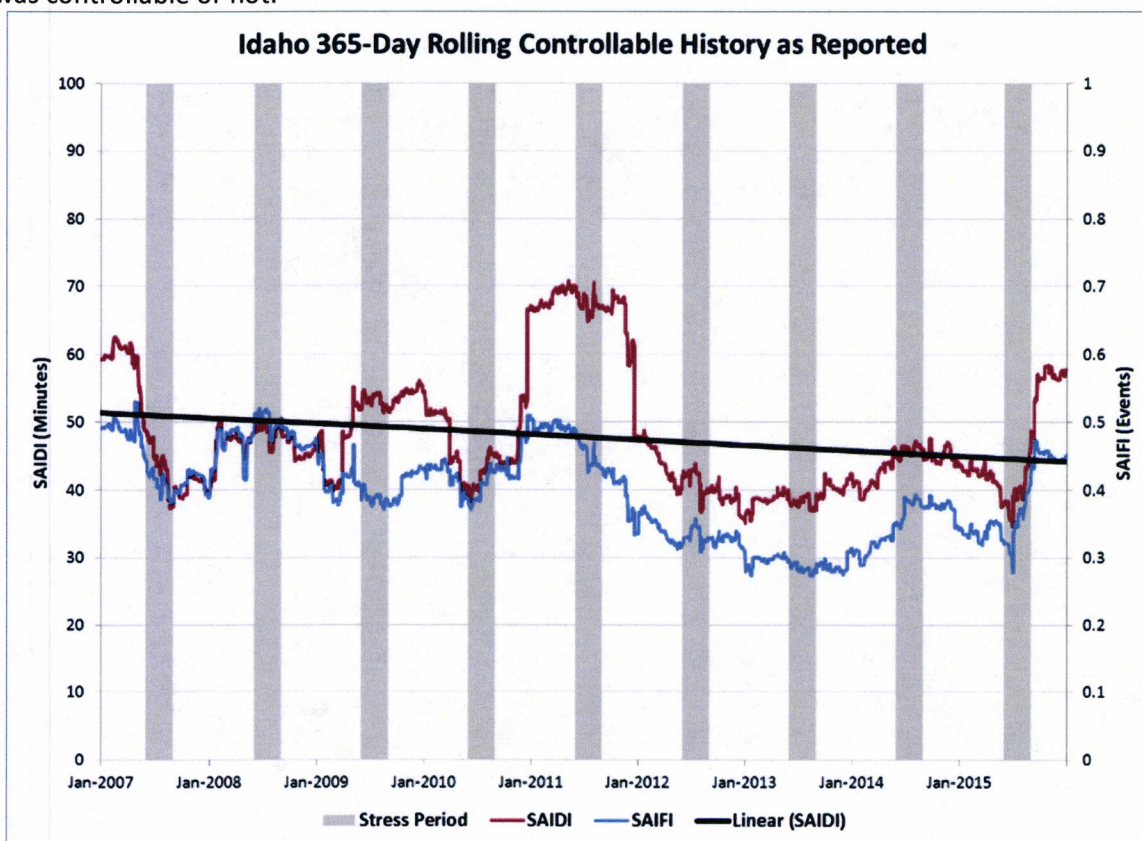
Depicted below is the history of reliability in Idaho. In 2002, the Company implemented an automated outage management system which provided the background information from which to engineer solutions for improved performance. Since the development of this foundational information, the Company has been in a position to improve performance, both in underlying and in extreme weather conditions. These improvements have included the application of geospatial tools to analyze reliability, development of web-based notifications when devices operate more than optimal, focus on operational responses via CAIDI metric analysis, in addition to feeder hardening programs when specific feeders have significantly impacted reliability performance.



## 2.5 Controllable, Non-Controllable and Underlying Performance Review

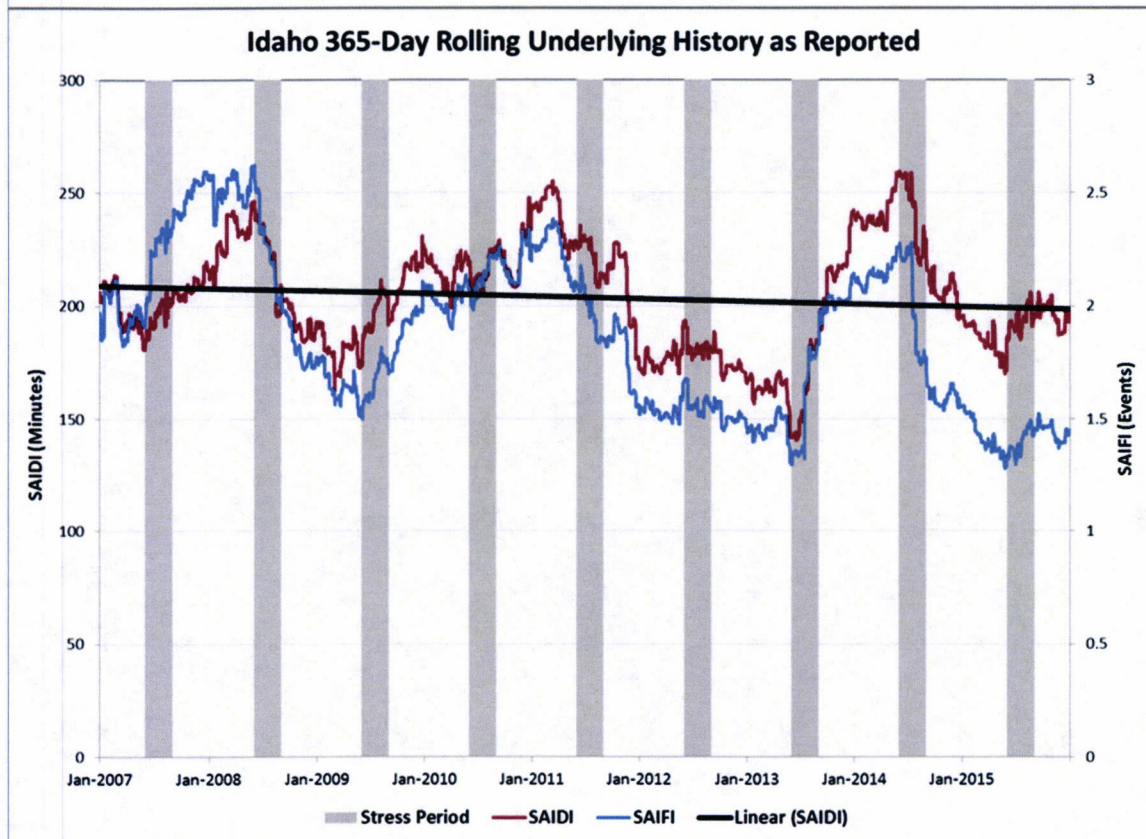
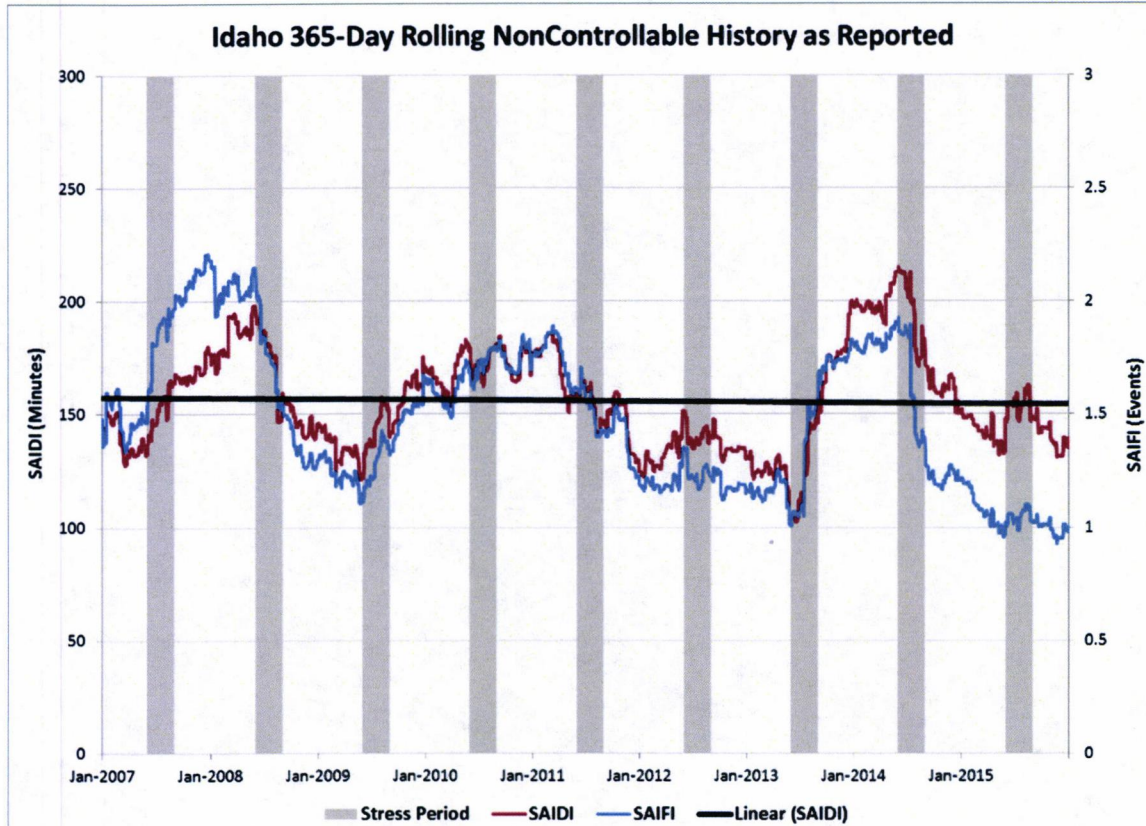
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as developed by engineering resources. This categorization was titled Controllable Distribution outages and recognized that certain types of outages can be cost-effectively avoided. So, for example, animal-caused interruptions, as well as equipment failure interruptions have a less random nature than lightning caused interruptions; other causes have also been determined and are specified in Section 2.5. Engineers can develop plans to mitigate against controllable distribution outages and provide better future reliability at the lowest possible cost. At that time, there was concern that the Company would lose focus on non-controllable outages<sup>8</sup>. In order to provide insight into the response and history for those outages, the charts below distinguish amongst the outage groupings. Plans are now centered on underlying performance, however the Company and Commission agreed that controllable distribution metrics would be valuable to continue to report.

The graphic history demonstrates controllable, non-controllable and underlying performance on a rolling 365-day basis. Analysis of the trends displayed in the charts below shows a general improving trend for all charts. In order to also focus on non-controllable outages, the Company has continued to improve its resilience to extreme weather using such programs as its visual assurance program to evaluate facility condition. It also has undertaken efforts to establish impacts of loss of supply events on its customers and deliver appropriate improvements when identified. It uses its web-based notification tool for alerting field engineering and operational resources when devices have exceeded performance thresholds in order to react as quickly as possible to trends in declining reliability. These notifications are conducted regardless of whether the outage cause was controllable or not.



<sup>8</sup> 3. The Company shall provide, as an appendix to its Service Quality Review reports, information regarding non-controllable outages, including, when applicable, descriptions of efforts made by the Company to improve service quality and reliability for causes the Company has identified as not controllable.

4. The Company shall provide a supplemental filing, within 90 days, consisting of a process for measuring performance and improvements for the non-controllable events.



## 2.6 Cause Code Analysis

The tables below outlines categories used in outage data collection. Subsequent charts and table use these groupings to develop patterns for outage performance.

Cause Category	Description and Examples
Environment	Contamination or Airborne Deposit (i.e. salt, trona, ash, other chemical dust, sawdust, etc.); corrosive environment; flooding due to rivers, broken water main, etc.; fire/smoke related to forest, brush or building fires (not including fires due to faults or lightning).
Weather	Wind (excluding windborne material); snow, sleet or blizzard; ice; freezing fog; frost; lightning.
Equipment Failure	Structural deterioration due to age (incl. pole rot); electrical load above limits; failure for no apparent reason; conditions resulting in a pole/cross arm fire due to reduced insulation qualities; equipment affected by fault on nearby equipment (i.e. broken conductor hits another line).
Interference	Willful damage, interference or theft; such as gun shots, rock throwing, etc.; customer, contractor or other utility dig-in; contact by outside utility, contractor or other third-party individual; vehicle accident, including car, truck, tractor, aircraft, manned balloon; other interfering object such as straw, shoes, string, balloon.
Animals and Birds	Any problem nest that requires removal, relocation, trimming, etc.; any birds, squirrels or other animals, whether or not remains found.
Operational	Accidental Contact by Rocky Mountain Power or Rocky Mountain Power's Contractors (including live-line work); switching error; testing or commissioning error; relay setting error, including wrong fuse size, equipment by-passed; incorrect circuit records or identification; faulty installation or construction; operational or safety restriction.
Loss of Supply	Failure of supply from Generator or Transmission system; failure of distribution substation equipment.
Planned	Transmission requested, affects distribution sub and distribution circuits; Company outage taken to make repairs after storm damage, car hit pole, etc.; construction work, regardless if notice is given; rolling blackouts.
Trees	Growing or falling trees
Other	Cause Unknown; use comments field if there are some possible reasons.

The table and charts below show the total customer minutes lost by cause and the total sustained interruptions by cause. The charts show each cause category's role in performance results and illustrate that certain types of outages account for a high amount of customer minutes lost but are infrequent, while others tend to be more frequent but account for few customer minutes lost.

The Underlying cause analysis table includes prearranged outages (*Customer Requested and Customer Notice Given* line items) with subtotals for their inclusion, while the grand totals in the table exclude these prearranged outages so that grand totals align with reported SAIDI and SAIFI metrics for the period. However, for ease of charting, the pie charts reflect the rollup-level cause category rather than the detail-level direct cause within each category. Therefore, the pie charts for Underlying include prearranged causes (listed within the *planned* category). Following the pie charts, a table of definitions provides descriptive examples for each direct cause category.

## 2.6.1 Underlying Cause Analysis Table

Idaho Cause Analysis - Underlying 01/01/2015 - 12/31/2015					
Direct Cause	Customer Minutes Lost for Incident	Customers in Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	184,279	1,854	189	2.38	0.024
BIRD MORTALITY (NON-PROTECTED SPECIES)	404,447	2,568	83	5.21	0.033
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	81,023	642	22	1.04	0.008
BIRD NEST (BMTS)	59,417	1,596	11	0.77	0.021
BIRD SUSPECTED, NO MORTALITY	202,050	2,447	70	2.60	0.032
<b>ANIMALS*</b>	<b>931,216</b>	<b>9,107</b>	<b>375</b>	<b>12.01</b>	<b>0.117</b>
FIRE/SMOKE (NOT DUE TO FAULTS)	1,499	23	5	0.02	0.000
<b>ENVIRONMENT</b>	<b>1,499</b>	<b>23</b>	<b>5</b>	<b>0.02</b>	<b>0.000</b>
B/O EQUIPMENT	276,082	3,578	165	3.56	0.046
DETERIORATION OR ROTTING	3,208,744	21,826	878	41.37	0.281
NEARBY FAULT	102	1	1	0.00	0.000
OVERLOAD	6,467	42	13	0.08	0.001
POLE FIRE	748,949	3,865	54	9.66	0.050
RELAYS, BREAKERS, SWITCHES	0	-	1	-	-
STRUCTURES, INSULATORS, CONDUCTOR	0	-	5	-	-
<b>EQUIPMENT FAILURE*</b>	<b>4,240,344</b>	<b>29,312</b>	<b>1,117</b>	<b>54.67</b>	<b>0.378</b>
DIG-IN (NON-COMPANY PERSONNEL)	54,089	294	38	0.70	0.004
OTHER INTERFERING OBJECT	33,890	368	17	0.44	0.005
OTHER UTILITY/CONTRACTOR	12,882	127	9	0.17	0.002
VANDALISM OR THEFT	2,573	4	1	0.03	0.000
VEHICLE ACCIDENT	927,111	7,054	84	11.95	0.091
<b>INTERFERENCE</b>	<b>1,030,545</b>	<b>7,847</b>	<b>149</b>	<b>13.29</b>	<b>0.101</b>
LOSS OF SUBSTATION	213,971	631	8	2.76	0.008
LOSS OF TRANSMISSION LINE	2,903,454	21,239	120	37.43	0.274
SYSTEM PROTECTION	0	-	2	-	-
<b>LOSS OF SUPPLY</b>	<b>3,117,424</b>	<b>21,870</b>	<b>130</b>	<b>40.19</b>	<b>0.282</b>
FAULTY INSTALL	4,556	59	6	0.06	0.001
IMPROPER PROTECTIVE COORDINATION	120	2	1	0.00	0.000
INCORRECT RECORDS	172	3	3	0.00	0.000
COMPANY EMPLOYEE - FIELD	224	2	2	0.00	0.000
<b>OPERATIONAL*</b>	<b>5,072</b>	<b>66</b>	<b>12</b>	<b>0.07</b>	<b>0.001</b>
OTHER, KNOWN CAUSE	5,442	236	25	0.07	0.003
UNKNOWN	632,373	6,818	433	8.15	0.088
<b>OTHER</b>	<b>637,814</b>	<b>7,054</b>	<b>458</b>	<b>8.22</b>	<b>0.091</b>
CONSTRUCTION	85,743	383	26	1.11	0.005
CONSTRUCTION - SCHEDULED SWITCHING	0	-	24	-	-
CUSTOMER NOTICE GIVEN	1,703,326	7,209	162	21.96	0.093
CUSTOMER REQUESTED	8,737	86	85	0.11	0.001
EMERGENCY DAMAGE REPAIR	847,402	12,327	148	10.93	0.159
INTENTIONAL TO CLEAR TROUBLE	173,582	1,083	11	2.24	0.014
MAINTENANCE	0	-	59	-	-
<b>PLANNED</b>	<b>2,818,790</b>	<b>21,088</b>	<b>515</b>	<b>36.34</b>	<b>0.272</b>

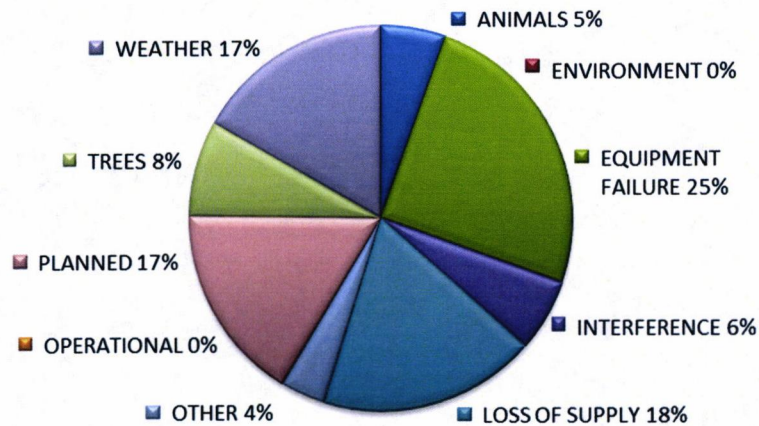
TREE - NON-PREVENTABLE	1,312,881	8,316	71	16.93	0.107
TREE – TRIMMABLE*	48,271	302	17	0.62	0.004
<b>TREES</b>	<b>1,361,152</b>	<b>8,618</b>	<b>88</b>	<b>17.55</b>	<b>0.111</b>
FREEZING FOG & FROST	241	2	2	0.00	0.000
ICE	482	4	4	0.01	0.000
LIGHTNING	621,193	4,318	172	8.01	0.056
SNOW, SLEET AND BLIZZARD	403,760	1,281	45	5.21	0.017
WIND	1,826,154	9,337	157	23.54	0.120
<b>WEATHER</b>	<b>2,851,831</b>	<b>14,942</b>	<b>380</b>	<b>36.77</b>	<b>0.193</b>
<b>Idaho Total</b>	<b>16,995,688</b>	<b>119,927</b>	<b>3,229</b>	<b>219.12</b>	<b>1.546</b>
<b>Idaho Underlying</b>	<b>15,283,625</b>	<b>112,632</b>	<b>2,958</b>	<b>197.05</b>	<b>1.452</b>

Note: Direct Causes are not listed if there were no outages classified within the cause during the reporting period.

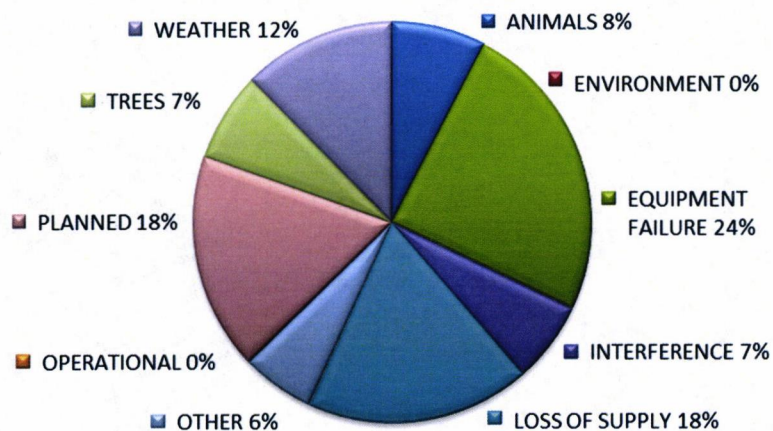
\*Controllable causes (Animal, Equipment Failure, Operational, and Tree-Trimable).

## 2.6.2 Cause Category Analysis Charts

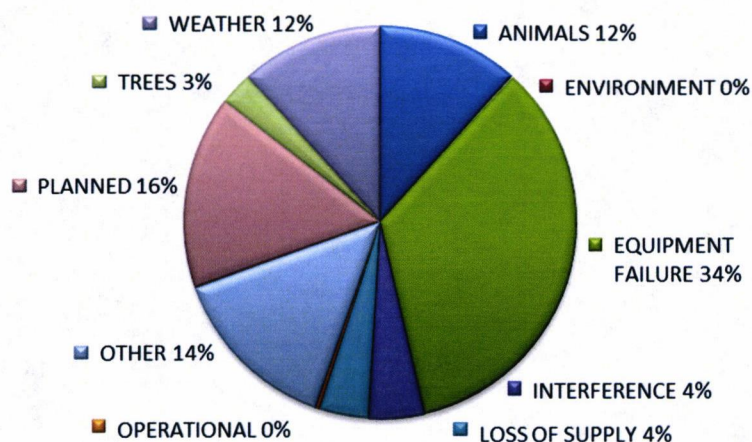
**Cause Analysis - Customer Minutes Lost (SAIDI)**



**Cause Analysis - Customer Interruptions (SAIFI)**



**Cause Analysis - Sustained Incidents**



## 2.7 Improve Worst Performing Circuits or Areas by Target Amount

In 2012 the Company modified its program with regards to selecting areas for improvement. Delivery of tools has allowed more targeted improvement areas. As a result, the Service Standard Program was modified to reflect this change. Prior to 2012, the company selected circuits as its most granular improvement focus; since then, groupings of service transformers are selected, however, if warranted entire distribution or transmission circuits could be selected.

### Circuit Performance Improvement (prior to 12/31/2011)

On a routine basis, the Company reviews circuits for performance. One measure that it uses is called circuit performance indicator (CPI), which is a blended weighting of key reliability metrics covering a three-year period. The higher the number, the poorer the blended performance the circuit is delivering. As part of the Company's Performance Standards Program, it annually selects a set of Worst Performing Circuits for targeted improvement. The improvement projects are generally completed within two years of selection. Within five years of selection, the average performance of the selection set must improve by at least 20% against baseline performance.

### Reliability Performance Improvement (post 12/31/2011)

On an annual routine basis, the Company reviews areas for performance. Utilizing a new measure called reliability performance indicator (RPI), which is a blended weighting of underlying reliability metrics covering a three-year period, calculated at the service transformer, excluding loss of supply outages. The higher the number, the poorer the blended performance the area has received. As part of the Company's Performance Standards Program, it annually selects Underperforming Areas for targeted improvement. The improvement projects are generally completed within two years of selection. Within five years of selection, the average performance of the selection set must improve by at least 10% against baseline performance.

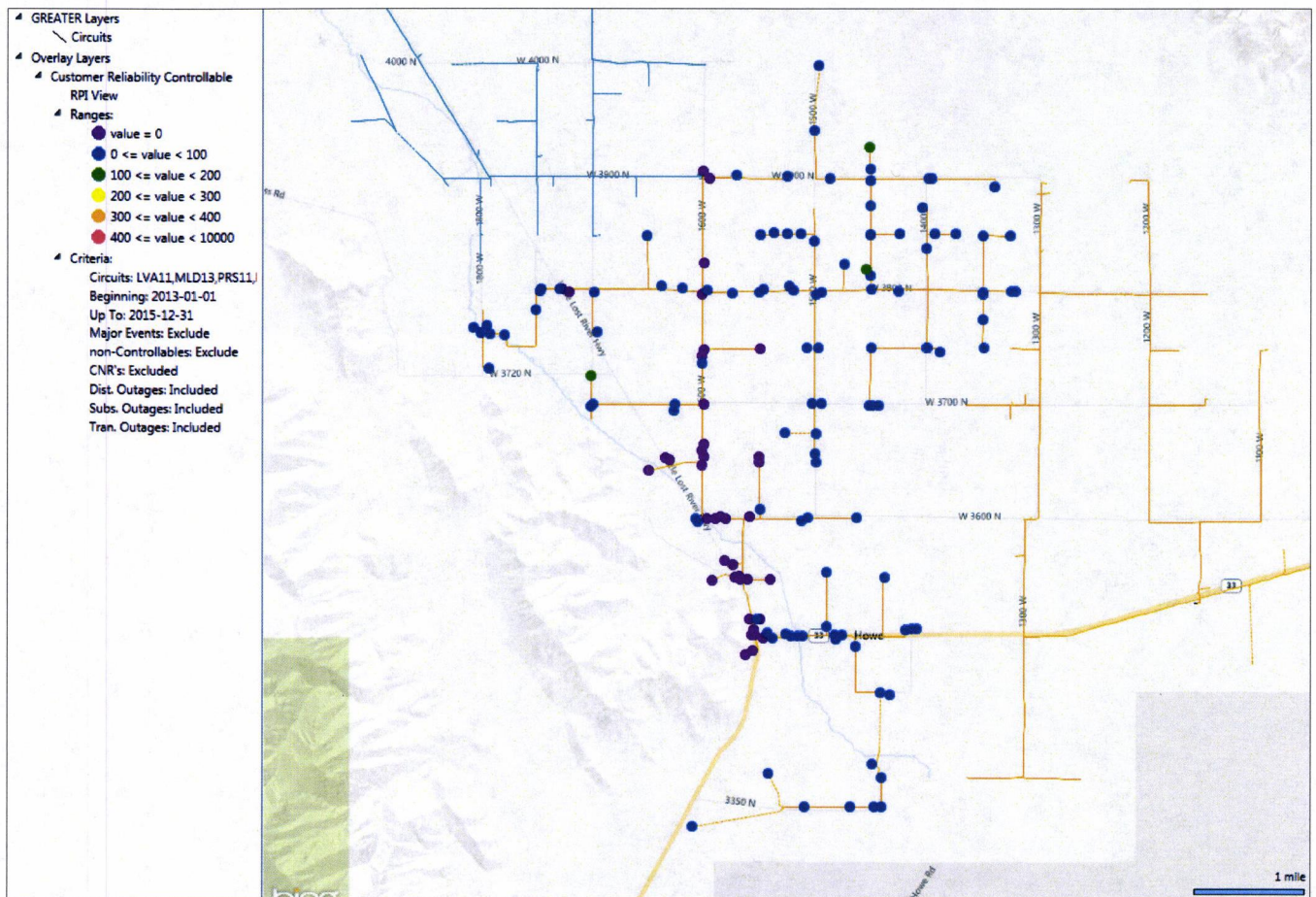
IDAHO WORST PERFORMING CIRCUITS	STATUS	BASELINE	PERFORMANCE 12/31/2015
<b>Region Performance Indicator 2012 (RPI<sup>12</sup>) Method</b>			
<b>PROGRAM YEAR 16 (CPI<sup>99</sup>) Method</b>			
Lava 11 (Figure 5C)	IN PROGRESS	127	123
Preston 11 (Figure 6C)	IN PROGRESS	36	64
<b>TARGET SCORE = 73</b>		<b>82</b>	<b>94</b>
<b>PROGRAM YEAR 15</b>			
Roberts 12 (Figure 3C)	COMPLETED	216	199
Targhee 11 (Figure 4C)	COMPLETED	176	180
<b>TARGET SCORE = 176</b>		<b>196</b>	<b>189</b>
<b>PROGRAM YEAR 14</b>			
Berenice 21 (Figure 1C)	COMPLETED	290	236
Malad 13 (Figure 2C)	COMPLETED	122	86
<b>TARGET SCORE = 185</b>	<b>GOAL MET</b>	<b>206</b>	<b>161</b>

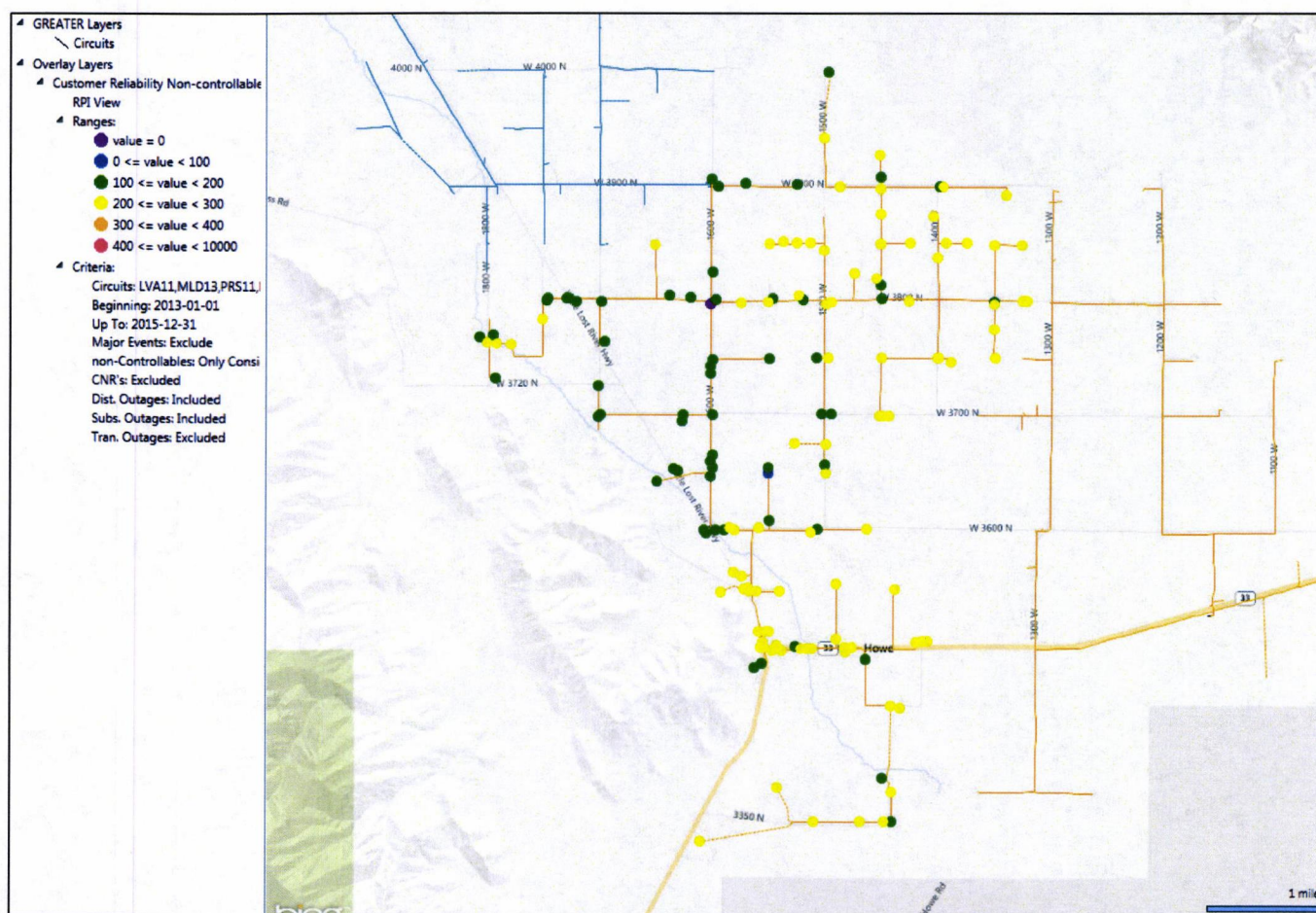
Circuit Performance Indicator 2005 (CPI <sup>05</sup> ) Method			
PROGRAM YEAR 12			
Grace 12	COMPLETED	124	53
Preston 13	COMPLETED	102	49
TARGET SCORE = 90	GOAL MET	113	51

(Improvement targets for circuits in Program Years 1 through 11 and 13 have been met and filed in prior reports.)

## 2.8 Geographic Outage History of Under-performing Areas

Figure 1A: Berenice 21 Controllable View





**Figure 1B: Berenice 21 Non-Controllable View**

Figure 1C: Berenice 21 Underlying View excluding Loss of Supply

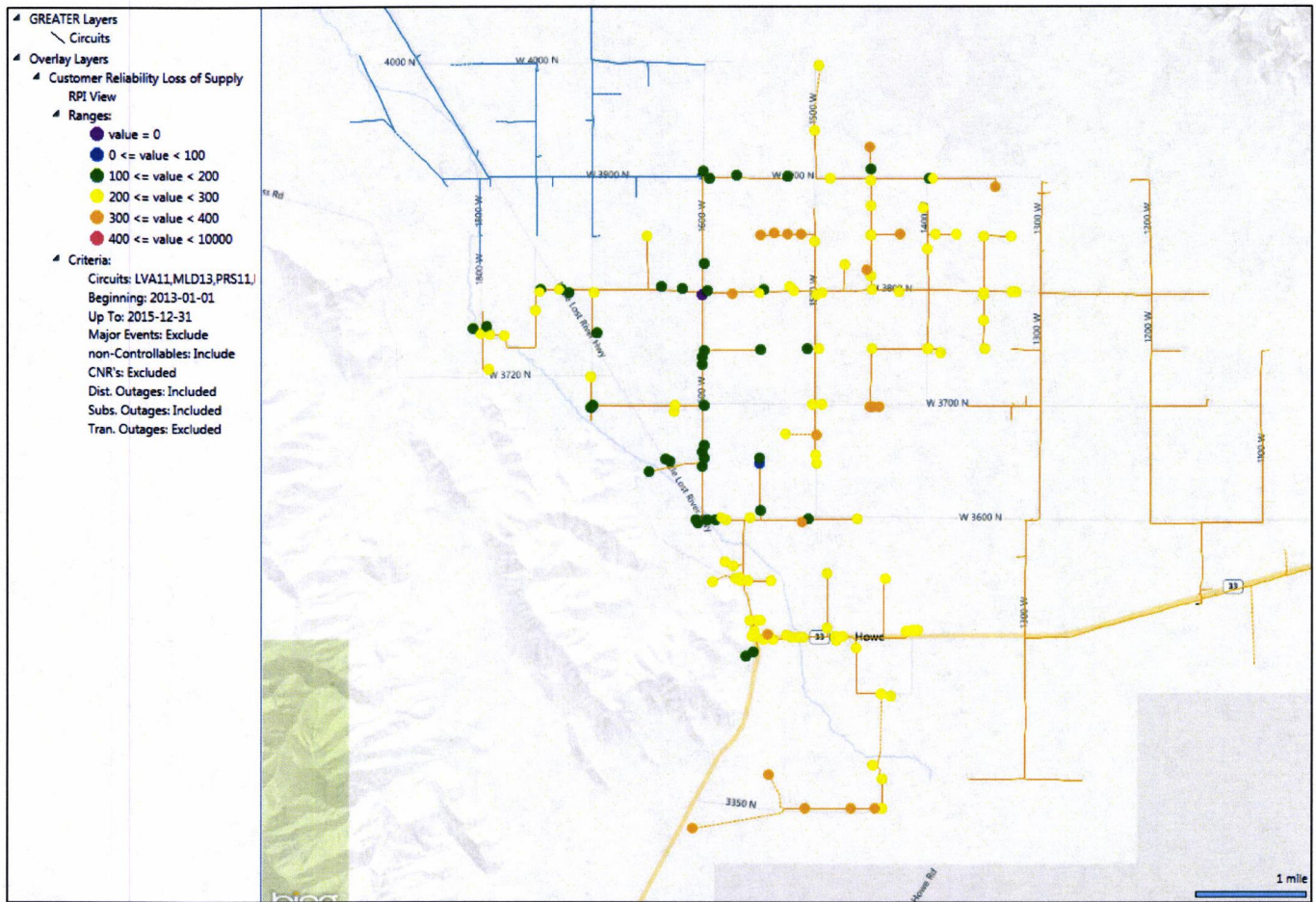
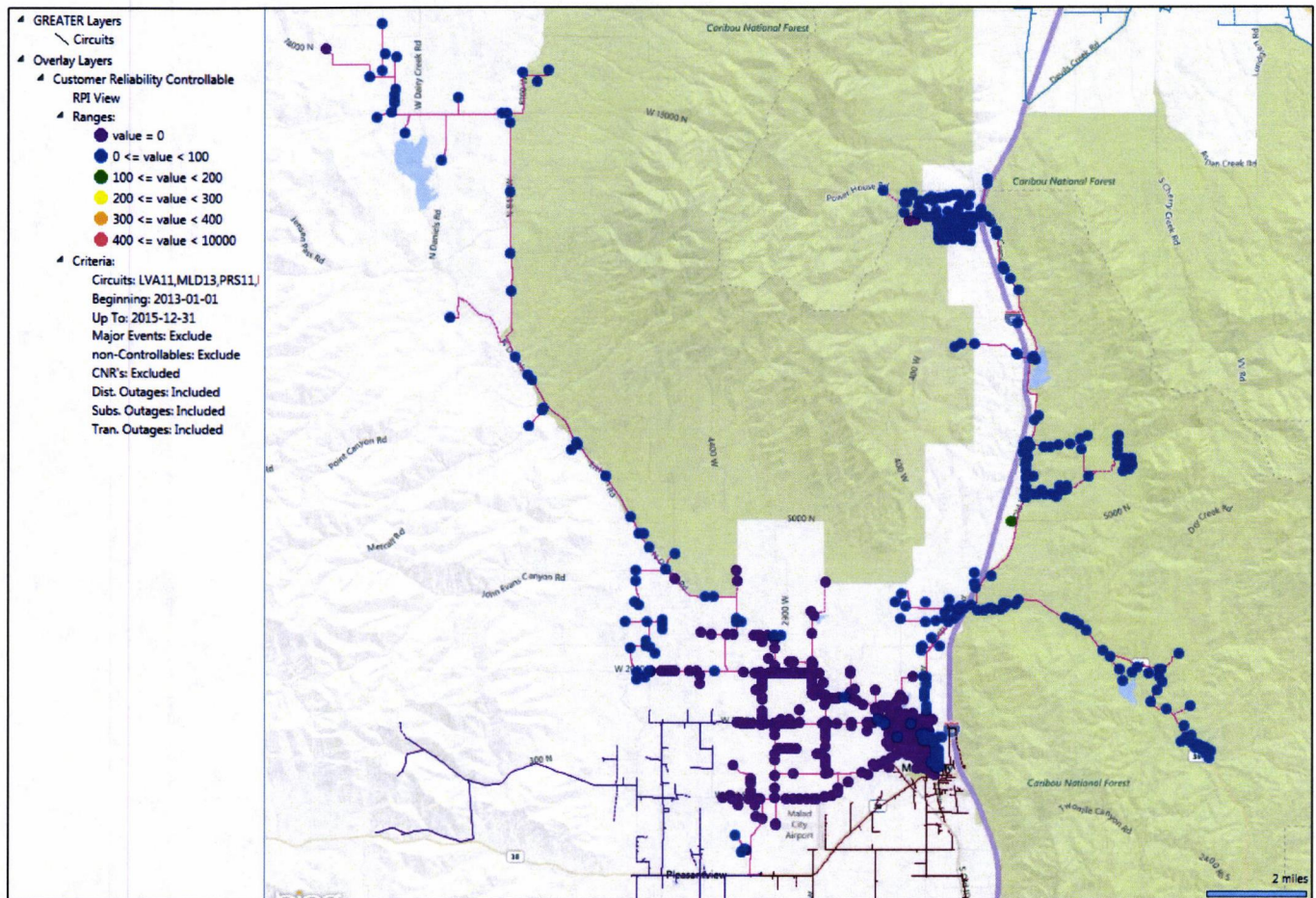
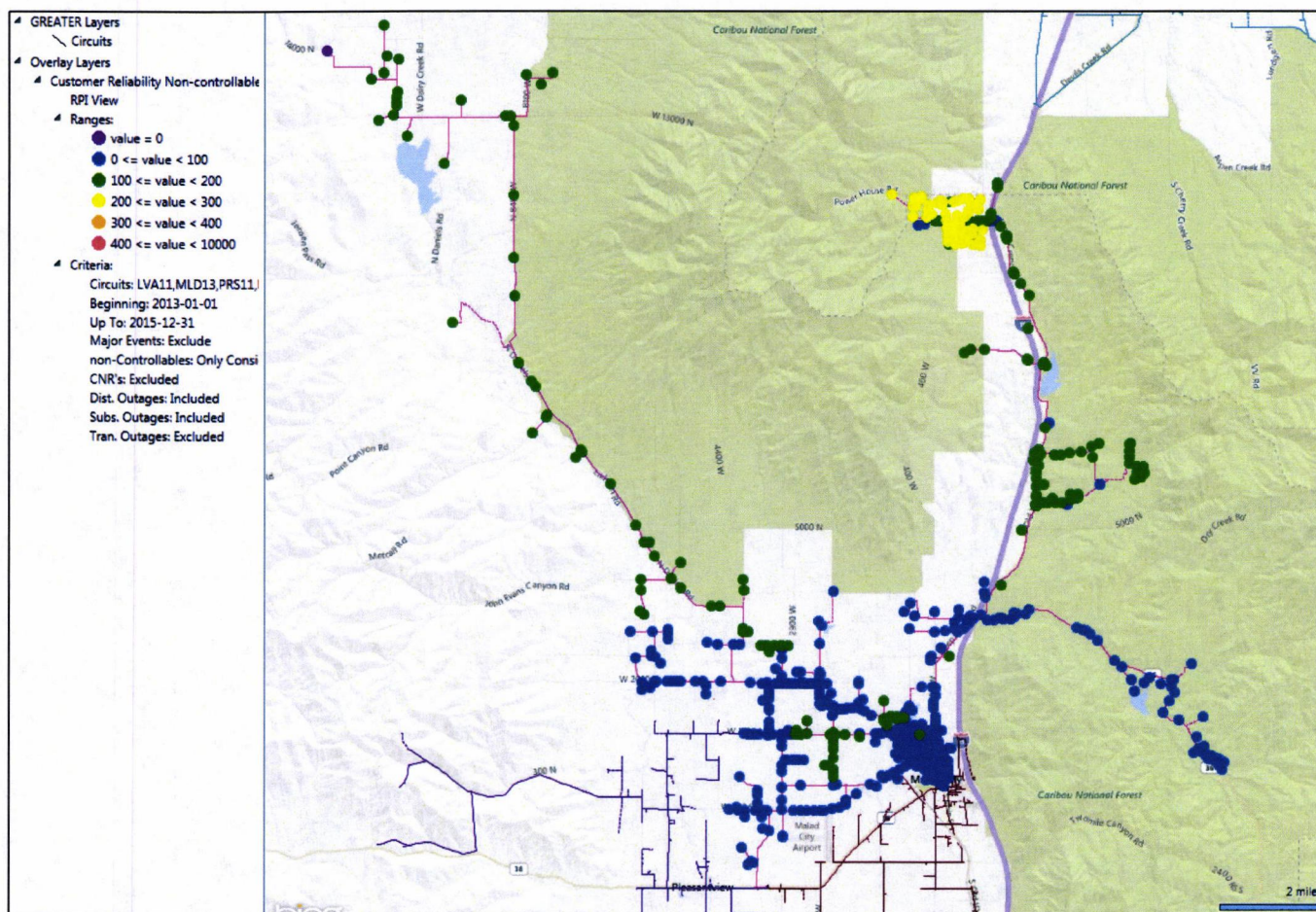


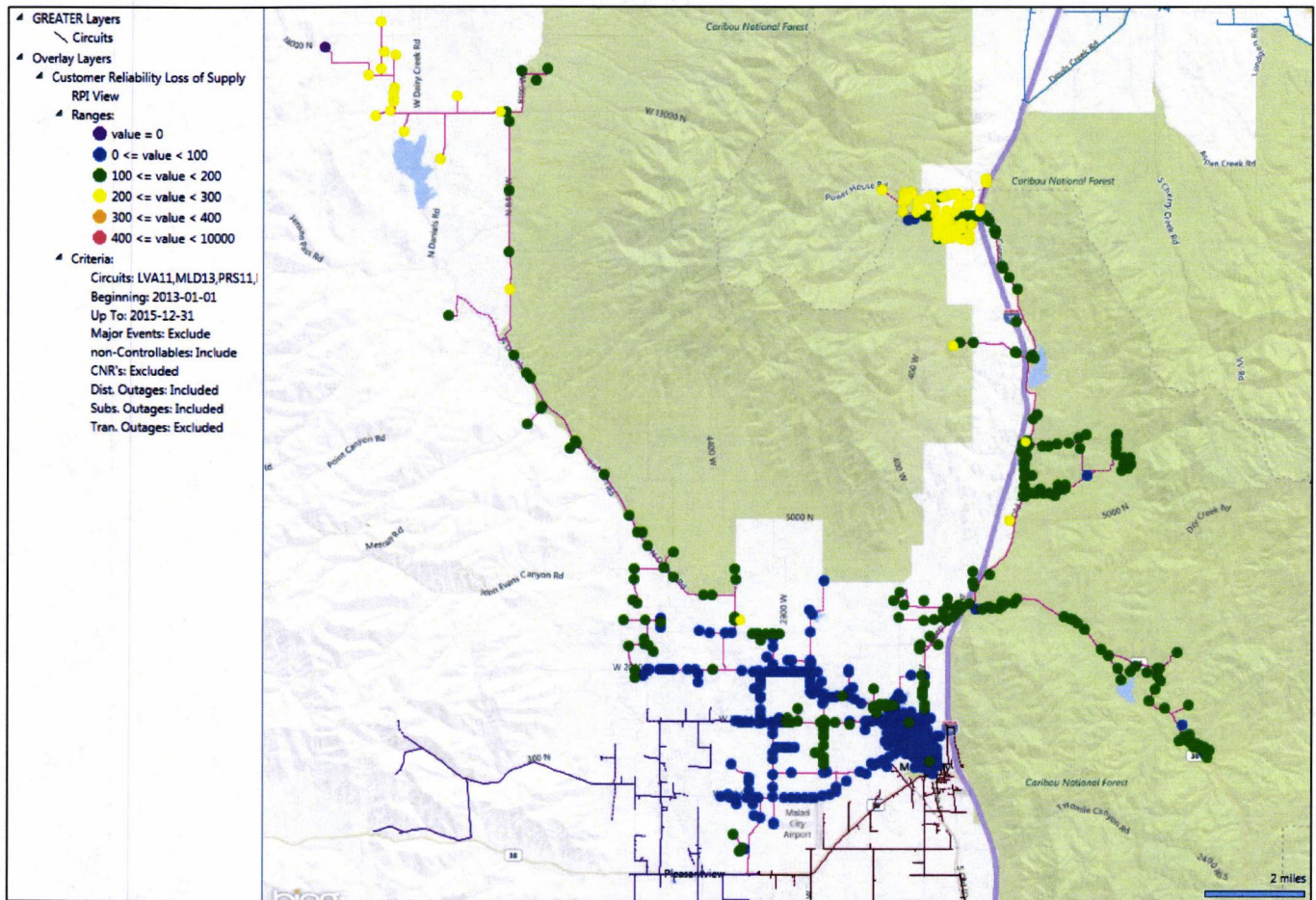
Figure 2A: Malad 13 Controllable View



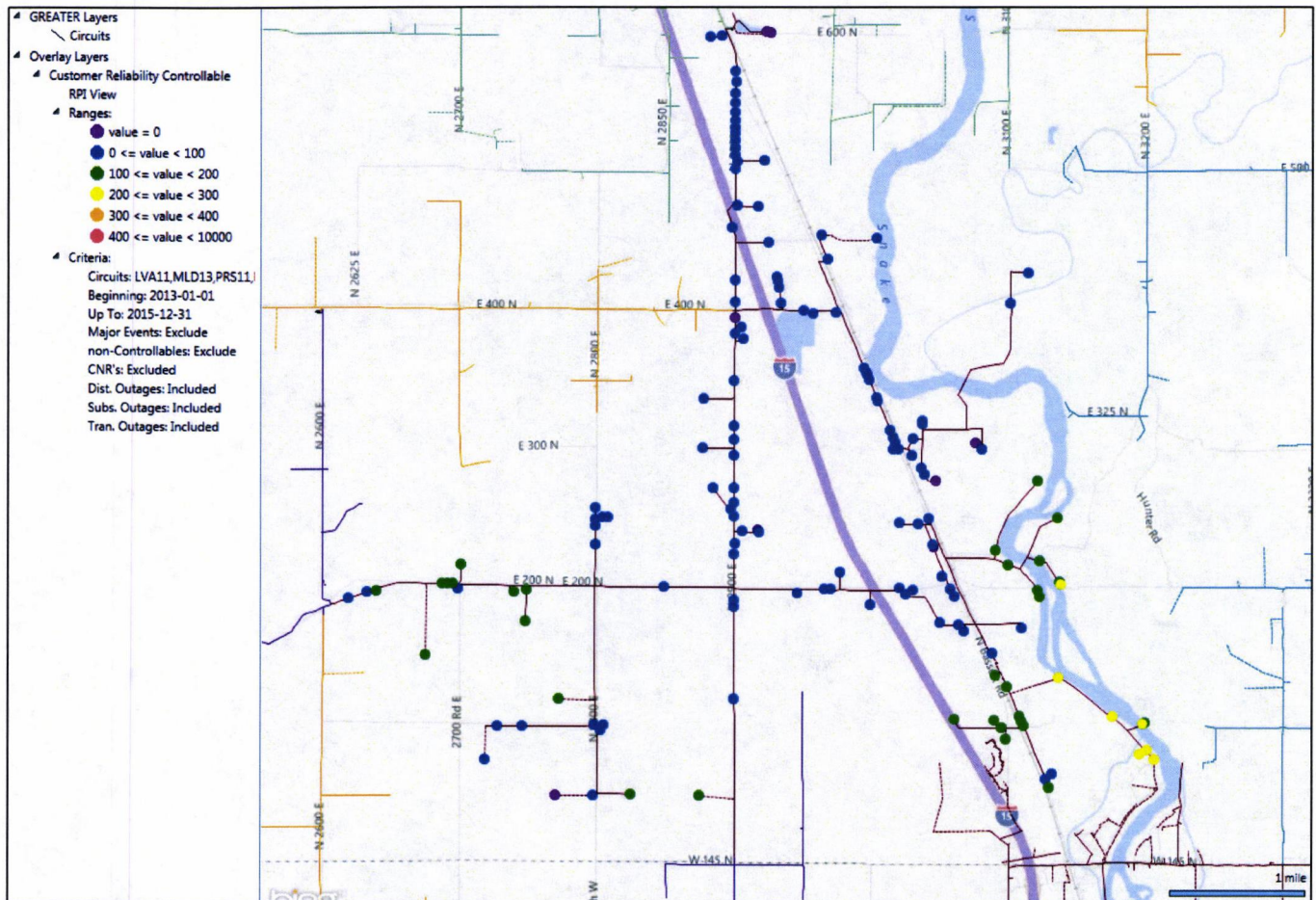
January – December 2015



**Figure 2C: Malad 13 Underlying View excluding Loss of Supply**

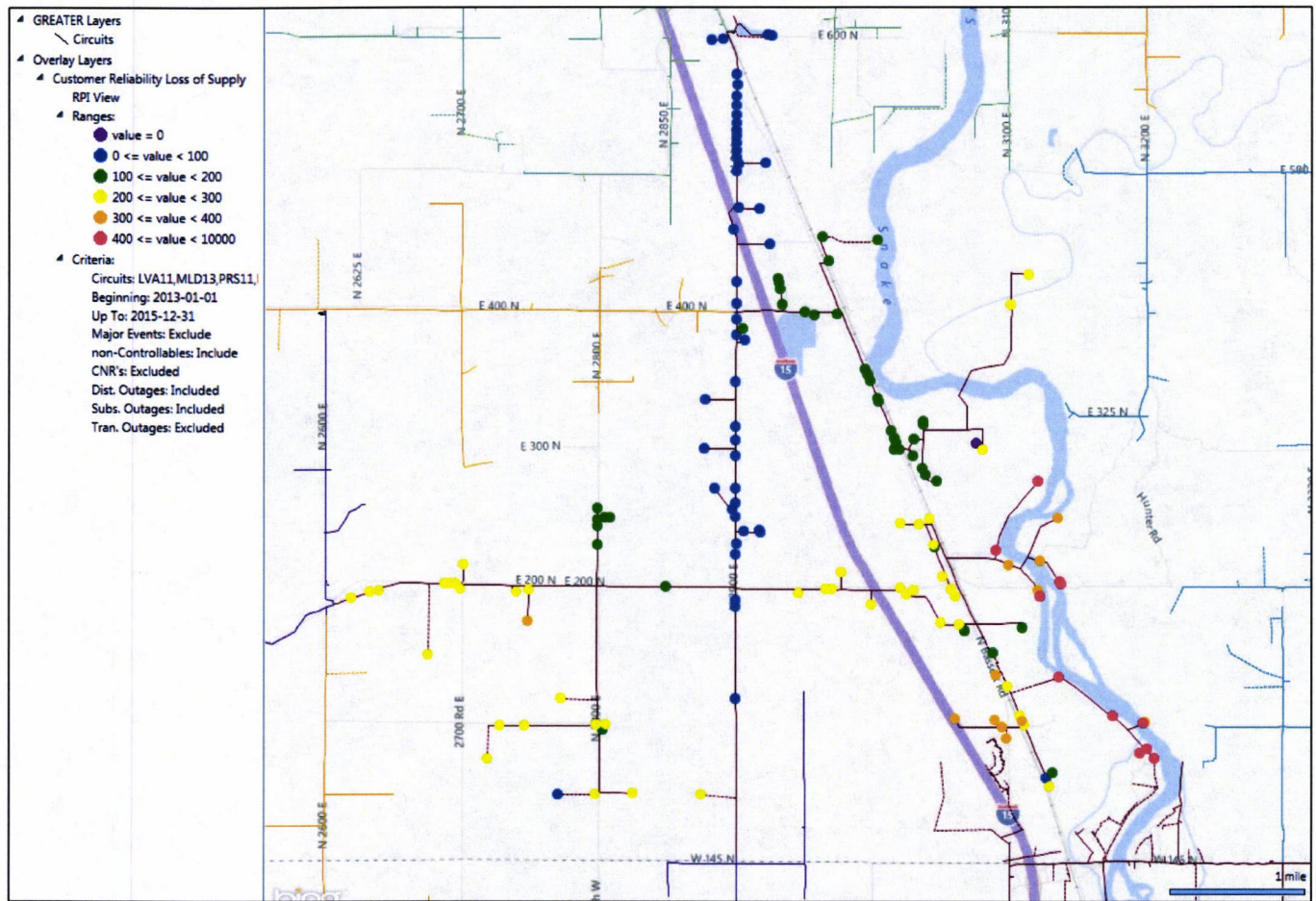


**Figure 3A: Roberts 12 Controllable View**



4 GREATER Layers  
   Circuits  
 4 Overlay Layers  
   Customer Reliability Non-controllable  
   RPI View  
   4 Ranges:  
     value = 0  
     0 <= value < 100  
     100 <= value < 200  
     200 <= value < 300  
     300 <= value < 400  
     400 <= value < 10000  
   4 Criteria:  
     Circuits: LVA11,MLD13,PRS11,  
     Beginning: 2013-01-01  
     Up To: 2015-12-31  
     Major Events: Exclude  
     non-Controllables: Only Consi  
     CNR's: Excluded  
     Dist. Outages: Included  
     Subs. Outages: Included  
     Tran. Outages: Excluded

Figure 3C: Roberts 12 Underlying View excluding Loss of Supply





January – December 2015

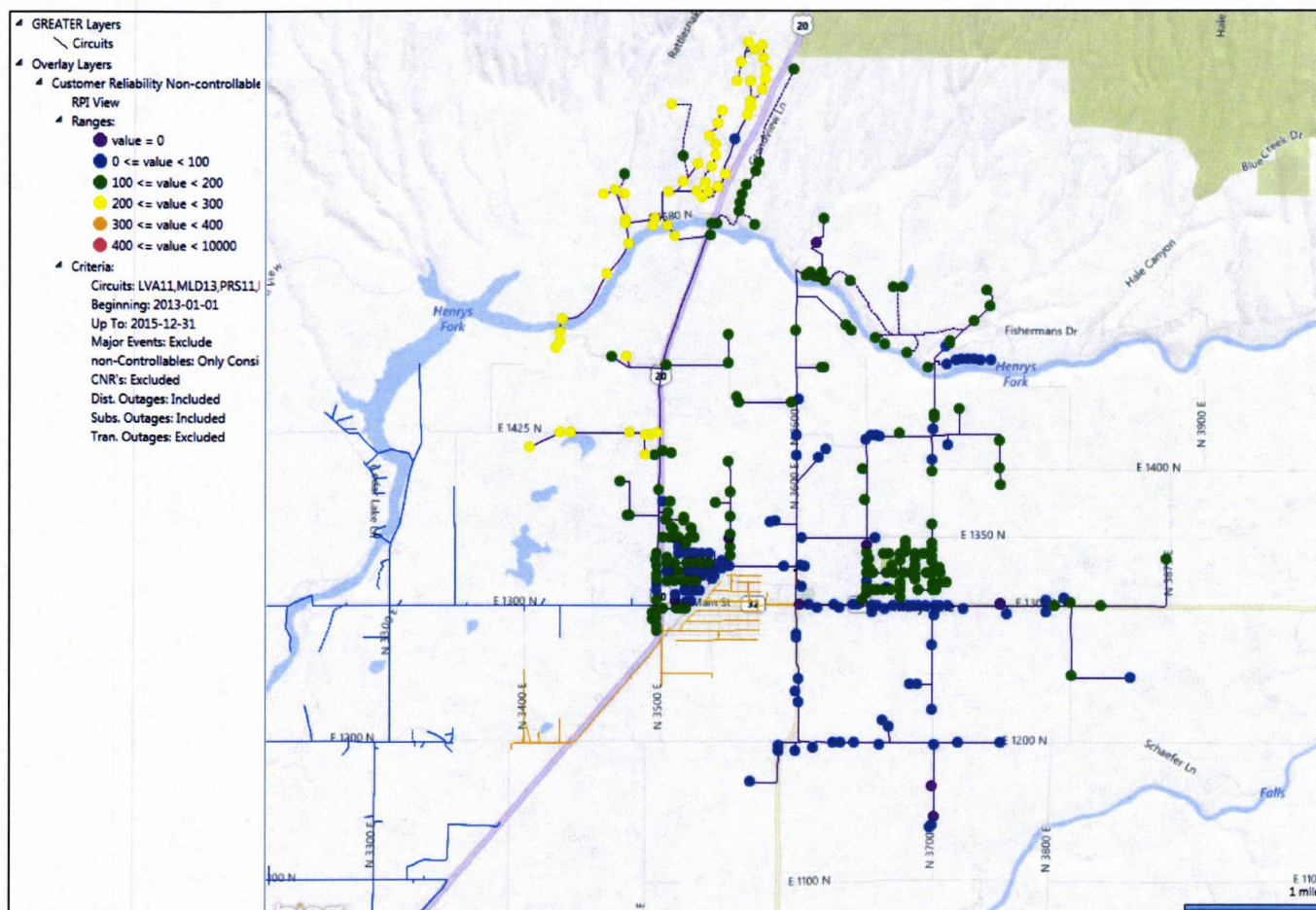


Figure 4C: Targhee 11 Underlying View excluding Loss of Supply

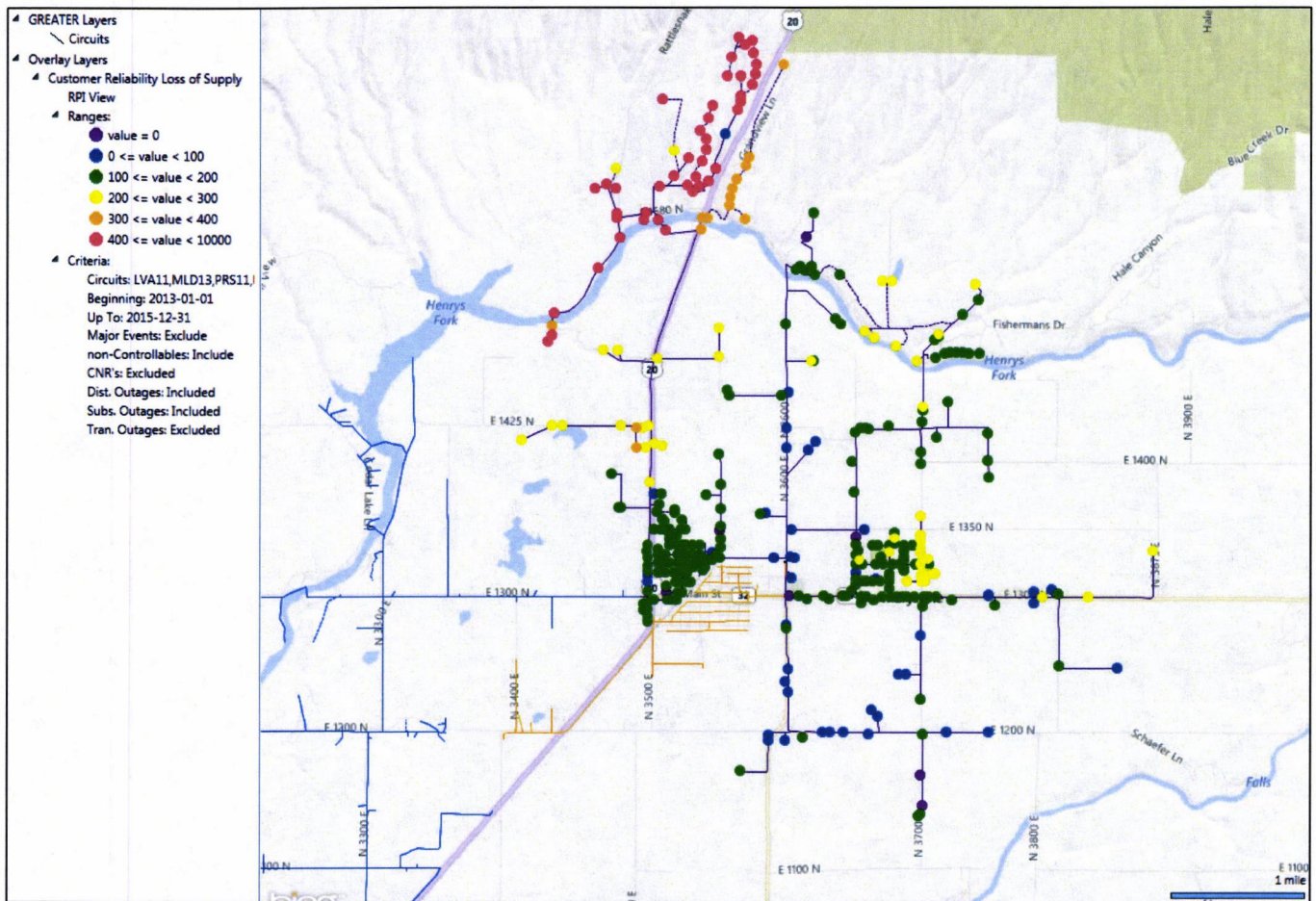
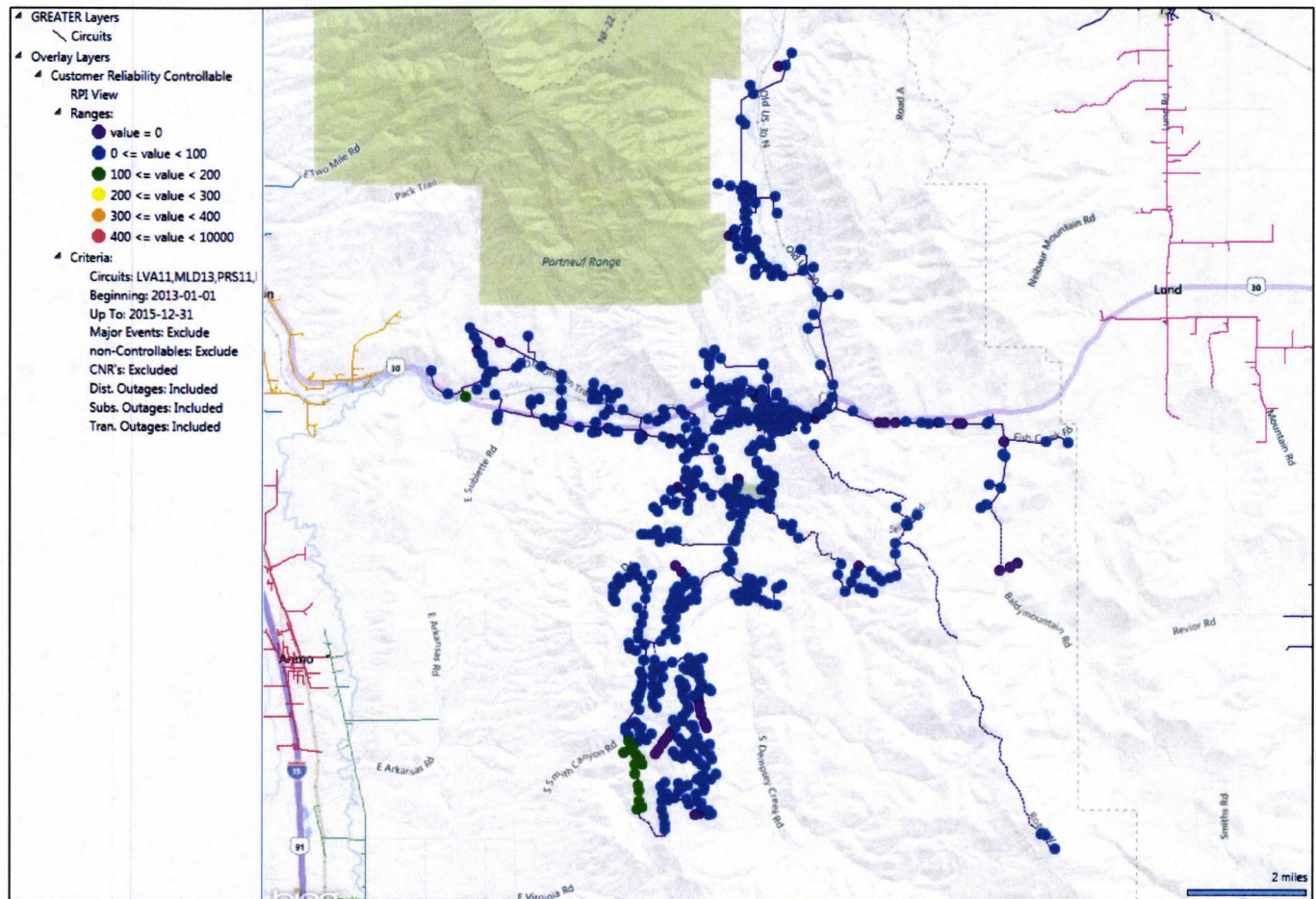


Figure 5A: Lava 11 Controllable View



January – December 2015

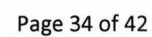
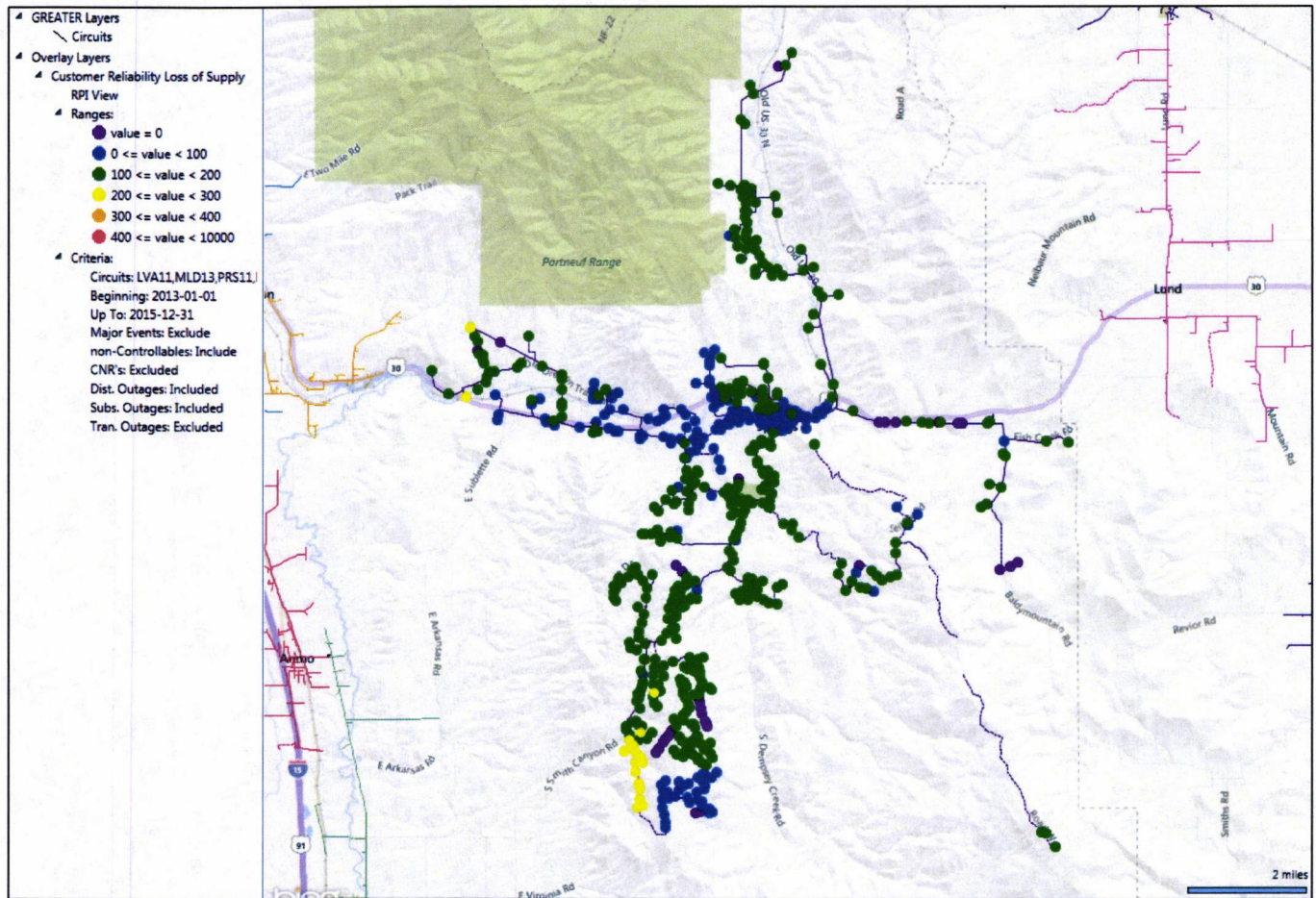


Figure 5C: Lava 11 Underlying View excluding Loss of Supply



**Figure 6A: Preston 11 Controllable View**

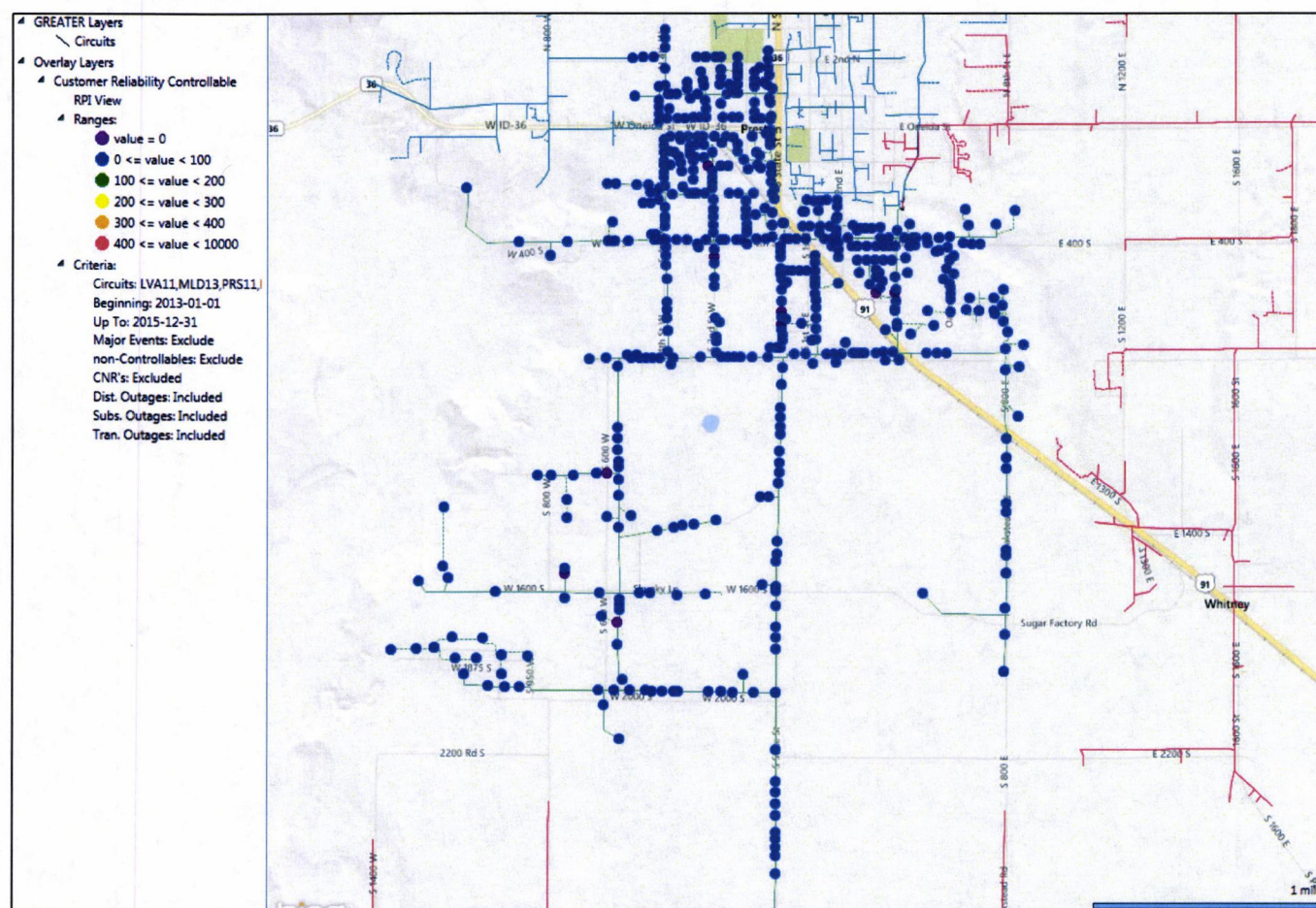


Figure 6B: Preston 11 Non-Controllable View

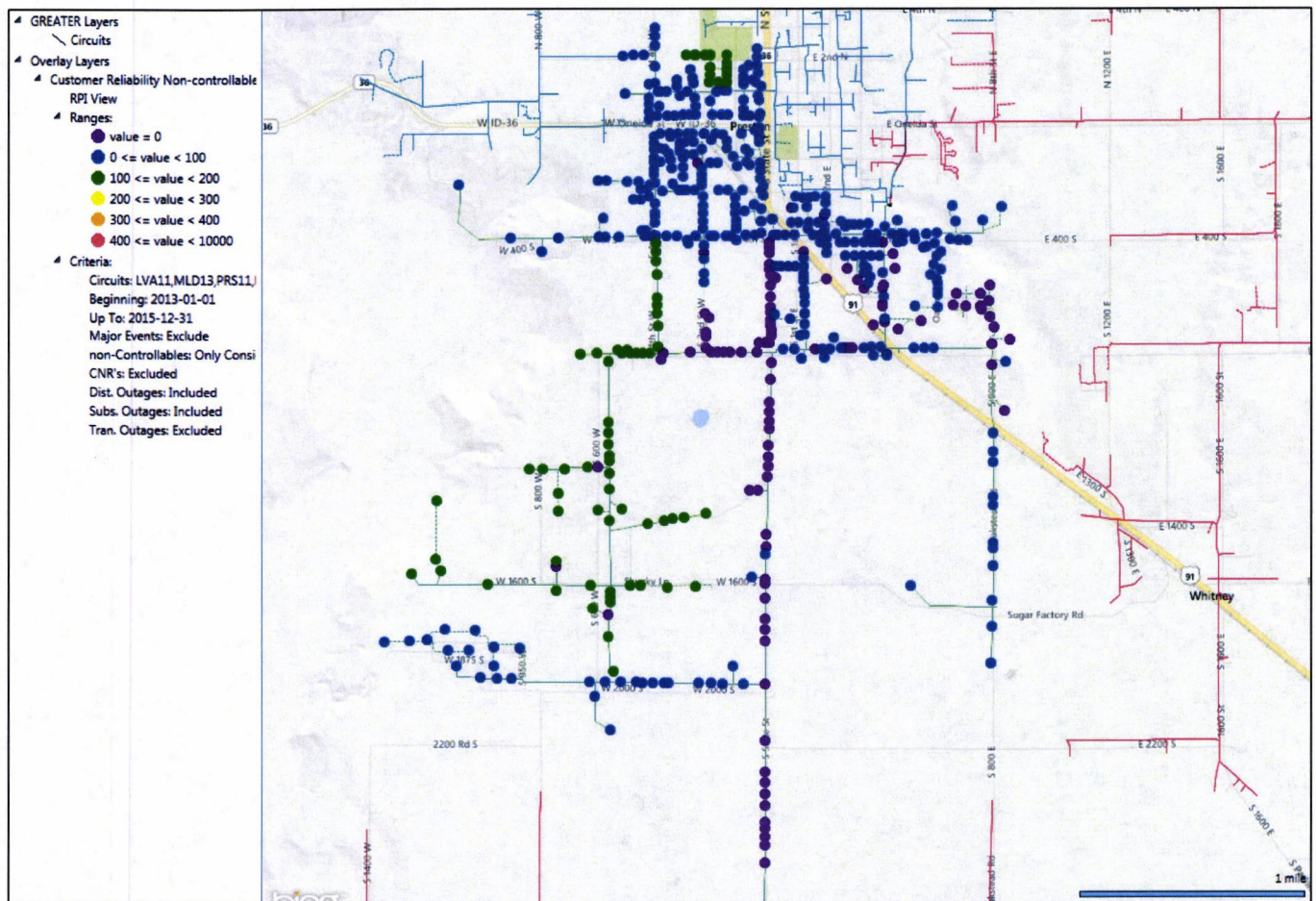
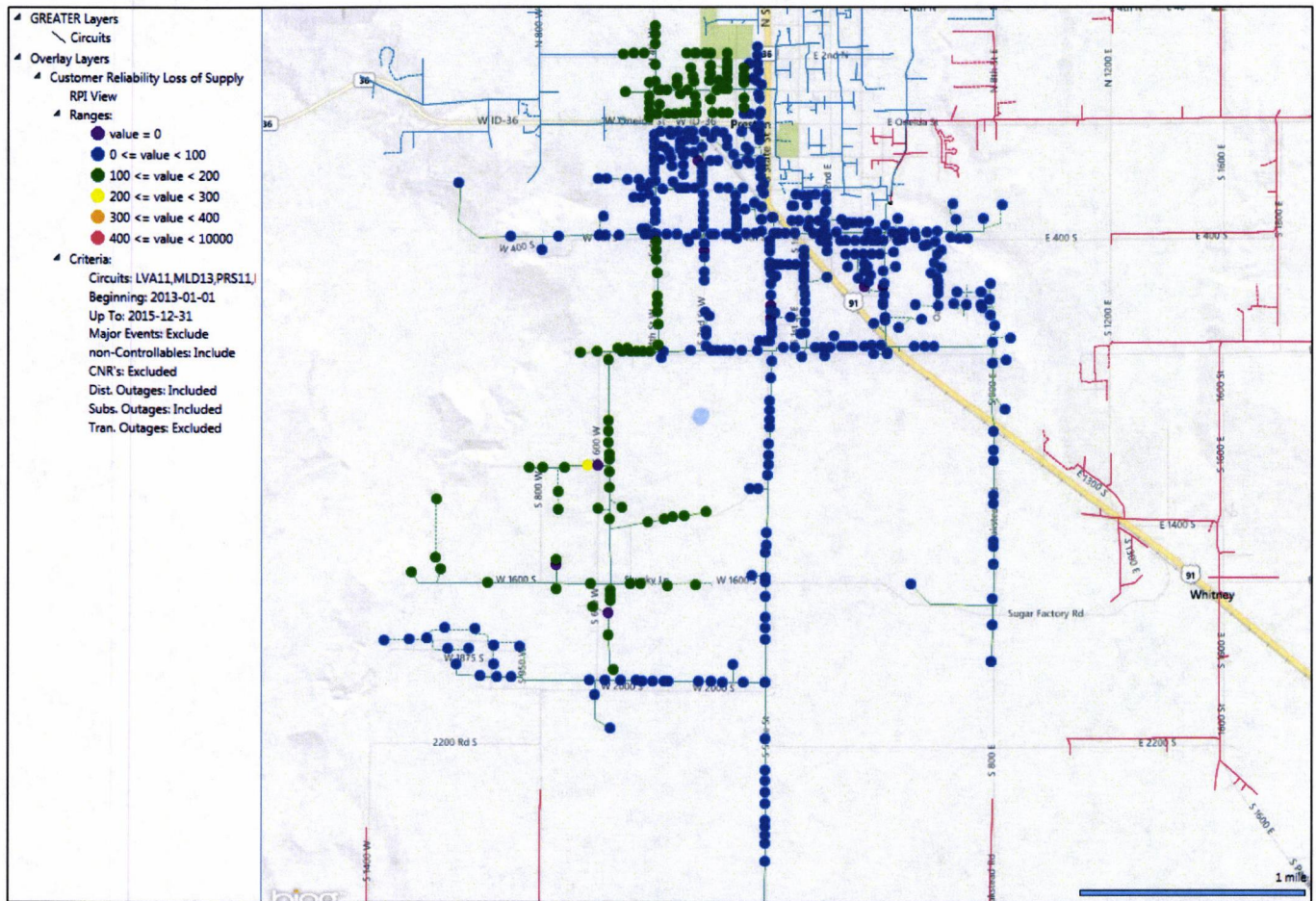


Figure 6C: Preston 11 Underlying View excluding Loss of Supply



## 2.9 Restore Service to 80% of Customers within 3 Hours

RESTORATIONS WITHIN 3 HOURS					
January 1 – December 31, 2015 = <b>88%</b>					
January	February	March	April	May	June
96%	94%	92%	88%	94%	82%
July	August	September	October	November	December
95%	71%	75%	77%	98%	93%

## 2.10 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	80%
PS6a) Respond to commission complaints within 3 days	95%	100%
PS6b) Respond to commission complaints regarding service disconnects within 4 hours	95%	100%
PS6c) Resolve commission complaints within 30 days	95%	100%

## 3 CUSTOMER GUARANTEES PROGRAM STATUS

Description	2015				2014			
	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid
CG1 Restoring Supply	112,633	0	100%	\$0	120,087	0	100%	\$0
CG2 Appointments	882	0	100%	\$0	768	1	99.87%	\$50
CG3 Switching on Power	550	0	100%	\$0	659	0	100%	\$0
CG4 Estimates	299	0	100%	\$0	290	0	100%	\$0
CG5 Respond to Billing Inquiries	383	0	100%	\$0	479	0	100%	\$0
CG6 Respond to Meter Problems	164	0	100%	\$0	161	0	100%	\$0
CG7 Notification of Planned Interruptions	7,209	6	99.92%	\$300	11,224	5	99.96%	\$250
	<b>122,120</b>	<b>6</b>	<b>99.9%</b>	<b>\$300</b>	<b>133,668</b>	<b>6</b>	<b>99.99%</b>	<b>\$300</b>

Overall Customer Guarantee performance remains above 99%, demonstrating Rocky Mountain Power's continued commitment to customer satisfaction.

Major Events are excluded from the Customer Guarantees program.

## 4 APPENDIX: Reliability Definitions

This section will define the various terms used when referring to interruption types, performance metrics and the internal measures developed to meet its performance plans.

### **Interruption Types**

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003/2012<sup>9</sup> Standard for Reliability Indices.

#### ***Sustained Outage***

A sustained outage is defined as an outage greater than 5 minutes in duration.

#### ***Momentary Outage Event***

A momentary outage event is defined as an outage equal to or less than 5 minutes in duration, and comprises all operations of the device during the momentary duration; if a breaker goes to lockout (it is unable to clear the faulted condition after the equipment's prescribed number of operations) the momentary operations are part of the ensuing sustained interruption. This sequence of events typically occurs when the system is trying to re-establish energy flow after a faulted condition, and is associated with circuit breakers or other automatic reclosing devices. Rocky Mountain Power uses the locations where SCADA (Supervisory Control and Data Acquisition) exists and calculates consistent with IEEE 1366-2003/2012. Where no substation breaker SCADA exists, fault counts at substation breakers are to be used.

### **Reliability Indices**

#### ***SAIDI***

SAIDI (system average interruption duration index) is an industry-defined term to define the average duration summed for all sustained outages a customer experiences in a given period. It is calculated by summing all customer minutes lost for sustained outages (those exceeding 5 minutes) and dividing by all customers served within the study area. When not explicitly stated otherwise, this value can be assumed to be for a one-year period.

#### ***Daily SAIDI***

In order to evaluate trends during a year and to establish Major Event Thresholds, a daily SAIDI value is often used as a measure. This concept is contained IEEE Standard 1366-2012. This is the day's total customer minutes out of service divided by the static customer count for the year. It is the total average outage duration customers experienced for that given day. When these daily values are accumulated through the year, it yields the year's SAIDI results.

#### ***SAIFI***

SAIFI (system average interruption frequency index) is an industry-defined term that attempts to identify the frequency of all sustained outages that the average customer experiences during a given period. It is calculated by summing all customer interruptions for sustained outages (those exceeding 5 minutes in duration) and dividing by all customers served within the study area.

#### ***CAIDI***

CAIDI (customer average interruption duration index) is an industry standard index that is the result of dividing the duration of the average customer's sustained outages by frequency of outages for that average customer. While the Company did not originally specify this metric under the umbrella of the Performance Standards Program within the context of the Service Standards Commitments, it has since been determined to be valuable for reporting purposes. It is derived by dividing PS1 (SAIDI) by PS2 (SAIFI).

<sup>9</sup> IEEE 1366-2003/2012 was first adopted by the IEEE Commissioners on December 23, 2003. The definitions and methodology detailed therein are now industry standards, which have since been affirmed in recent balloting activities.

### MAIFI<sub>E</sub>

MAIFI<sub>E</sub> (momentary average interruption event frequency index) is an industry standard index that quantifies the frequency of all momentary interruption events that the average customer experiences during a given time-frame. It is calculated by counting all momentary interruptions which occur within a 5 minute time period, as long as the interruption event did not result in a device experiencing a sustained interruption.

### CEMI

CEMI is an acronym for Customers Experiencing Multiple (Sustained and Momentary) Interruptions. This index depicts repetition of outages across the period being reported and can be an indicator of recent portions of the system that have experienced reliability challenges. This metric is used to evaluate customer-specific reliability.

### CPI99

CPI99 is an acronym for Circuit Performance Indicator, which uses key reliability metrics of the circuit to identify underperforming circuits. It excludes Major Event and Loss of Supply or Transmission outages. The variables and equation for calculating CPI are:

$$\text{CPI} = \text{Index} * ((\text{SAIDI} * \text{WF} * \text{NF}) + (\text{SAIFI} * \text{WF} * \text{NF}) + (\text{MAIFI} * \text{WF} * \text{NF}) + (\text{Lockouts} * \text{WF} * \text{NF}))$$

Index: 10.645

SAIDI: Weighting Factor 0.30, Normalizing Factor 0.029

SAIFI: Weighting Factor 0.30, Normalizing Factor 2.439

MAIFI: Weighting Factor 0.20, Normalizing Factor 0.70

Lockouts: Weighting Factor 0.20, Normalizing Factor 2.00

Therefore,  $10.645 * ((3\text{-year SAIDI} * 0.30 * 0.029) + (3\text{-year SAIFI} * 0.30 * 2.439) + (3\text{-year MAIFI} * 0.20 * 0.70) + (3\text{-year breaker lockouts} * 0.20 * 2.00)) = \text{CPI Score}$

### CPI05

CPI05 is an acronym for Circuit Performance Indicator, which uses key reliability metrics of the circuit to identify underperforming circuits. Unlike CPI99 it includes Major Event and Loss of Supply or Transmission outages. The calculation of CPI05 uses the same weighting and normalizing factors as CPI99.

### RPI

RPI is an acronym for Reliability Performance Indicator, which measures reliability performance on a specific segment of a circuit to identify underperforming circuit segments rather than measuring performance of the whole circuit. This is the company's refinement to its historic CPI, more granular.

## Performance Types & Commitments

Rocky Mountain Power recognizes several categories of performance; major events and underlying performance. Underlying performance days may be significant event days. Outages recorded during any day may be classified as "controllable" events.

### Major Events

A Major Event (ME) is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value (Reliability Standard IEEE 1366-2012) based on the 2.5 beta methodology. The values used for the reporting period and the prospective period are shown below.

### Significant Events

The Company has evaluated its year-to-year performance and as part of an industry weather normalization task force, sponsored by the IEEE Distribution Reliability Working Group, determined that when the Company recorded a day in excess of 1.75 beta (or 1.75 times the natural log standard deviation beyond the natural log daily average for the day's SAIDI) that generally these days' events are generally associated with weather events and serve as an indicator of a day which accrues substantial reliability metrics, adding to the cumulative

reliability results for the period. As a result, the Company individually identifies these days so that year-on-year comparisons are informed by the quantity and their combined impact to the reporting period results.

***Underlying Events***

Within the industry, there has been a great need to develop methodologies to evaluate year-on-year performance. This has led to the development of methods for segregating outlier days, via the approaches described above. Those days which fall below the statistically derived threshold represent “underlying” performance, and are valid. If any changes have occurred in outage reporting processes, those impacts need to be considered when making comparisons. Underlying events include all sustained interruptions, whether of a controllable or non-controllable cause, exclusive of major events, prearranged and customer requested interruptions.

***Controllable Distribution (CD) Events***

In 2008, the Company identified the benefit of separating its tracking of outage causes into those that can be classified as “controllable” (and thereby reduced through preventive work) from those that are “non-controllable” (and thus cannot be mitigated through engineering programs); they will generally be referred to in subsequent text as controllable distribution (CD). For example, outages caused by deteriorated equipment or animal interference are classified as controllable distribution since the Company can take preventive measures with a high probability to avoid future recurrences; while vehicle interference or weather events are largely out of the Company’s control and generally not avoidable through engineering programs. (It should be noted that Controllable Events is a subset of Underlying Events. The *Cause Code Analysis* section of this report contains two tables for Controllable Distribution and Non-controllable Distribution, which list the Company’s performance by direct cause under each classification.) At the time that the Company established the determination of controllable and non-controllable distribution it undertook significant root cause analysis of each cause type and its proper categorization (either controllable or non-controllable). Thus, when outages are completed and evaluated, and if the outage cause designation is improperly identified as non-controllable, then it would result in correction to the outage’s cause to preserve the association between controllable and non-controllable based on the outage cause code. The company distinguishes the performance delivered using this differentiation for comparing year to date performance against underlying and total performance metrics.